North Sea FLOW Measurement Workshop

1995

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NORTH SEA FLOW MEASUREMENT WORKSHOP

Lillehammer, 24-26 October 1995

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OPENING ADDRESS

by

Jan B O S I O

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Ladies and gentlemen, I am really honored to address this experienced and professional audience at the 13 th venue of the North Sea Flow Measurement Workshop here at Lillehammer. I have the pleasure to know many of you for many years and this makes my opening address more challenging, at least for me, but also perhaps more open as I can touch upon central issues which I feel are of concern to all of us.

The metering specialists of all kinds such as the users of equipment, the manufacturers and the R&D community are all involved in the broad effort initiated by the oil& gas industry to reduce the development costs in the offshore activities by 50% in the years to come.

The question comes inevitably in mind: how does metering contributes to this effort? I pretend that we have a significant role to play. To demonstrate my statement I will focus on the following examples:

- the implementation of new technologies
- cooperation between the different metering actors
- development of appropriate standards and procedures
- Quality assurance

Implementation of new technologies

We have for the first time at the North Sea Flow Measurement Workshop offered a separate session on **Multiphase metering** demonstrating the importance that this topic deserves. Every one is familiar with the potential cost savings which can be realised if the production fields are developed based on a multiphase transport. To make such development possible we need, among other things, a reliable and performant metering equipment. Even though the development of the technology of multiphase or more precisely two-phase flow metering started back in the 60 ties, essentially to meet

the requirements of the nuclear industry, it took some time before the oil and gas industry in the North Sea area became interested in the technology. This occurred in the beginning of the 80ties. The task to adapt the technology gained from the nuclear industry to the needs of the oil and gas industry has been arduous. If our managers at the very early beginning had anticipated how long time and how much it would cost to reach the level of knowledge and competence that we have today, they might have denied to put money in that race. My estimate is that at least 1500 million Norwegian crowns (150 MGBP), based on an average spending of 10 MNOK per year by, let say 10 oil companies over 15 years, have been invested into the development of the multiphase flow technology, including metering, pumping and process technology. It is a huge amount of money, but only approximately 2% of the investment made for the construction of the Eurotunnel.

To day the technology of metering multiphase flow has reached an almost mature level, which means that we have the understanding of the problems to be solved in order to manufacture reliable and performant meters. The manufacturers, the reasearch institutes and universities and the users have jointly contributed to this achievement. Intentionnally I do not nominate any of them because I could forget some, but all of them deserve a great thank for having made possible real cost savings in the development of new production fields.

The results of the ongoing test programmes on multiphase metering which will be presented on Wednesday will offer an updated status of the achievements which have been reached since the last Workshop in Peebles.

As a contribution to attain a common platform of technology understanding some of our colleagues in Norway have prepared what we have called Handbook of Multiphase Metering. I take the opportunity to acknowledge the excellent job that they have done which should help us to reach a common understanding on the terminology and the functional requirements of multiphase flowmeters.

The second domain that I would like to address is the **ultrasonic flowmeter** for gas metering. It is recognised that its features will bring substantial cost savings into the metering installations, especially offshore. Today we are at a breakthroug. After a promising start at the end of the 70ties it has taken some years before the technology reached the industrial stage. In that respect we have to acknowledge the constant effort and belief in the device demonstrated by some pioneers. It remains today to assess the performance of the ultrasonic gas flowmeter under the different operation conditions that we experience along the gas production and transportation chain, especially the meters behaviour in high temperature and noisy environment.

Although the meter has not yet reached the complete fiscal status, it is accepted as an allocation meter by the Norwegian authorities, research work initiated by GERG, the European Group for Gas Reasearch, and the GRI-sponsored research in USA should lead to the definite recognition of ultrasonic flowmeter as fiscal meter within a couple of years.

My conclusion from these two examples is that these new technologies will effectively contribute to improve the economics of the gas production and transportation activities. The experience has however proved that the time and the money spent from day one, when the bright idea comes to your mind, to the day you can offer to the user a reliable and performant equipment is always underestimated.

Cooperation between the different actors

Here we touch upon the second topic that I would like to address and which summarises to: pull and push together!

It has always been a conflict between the strategic objective of a company to protect its R&D activities and technology and the benefit which could arise by joining in pools of actors. The world is only from time to time as we would like to see it, so my above statement should be amended based on the particularities present in each special situation.

The cost of developing new tools to improve metering has become very expensive as the requirements to qualify new equipments imply testing at operating conditions, which tend to be extremely severe when we consider offshore installations. On the other side it is offshore where the largest savings with respect to investment cost can be made. In that situation making appropriate alliances reduce the cost involved with a project and make possible a higher activity level.
During the last year we have seen the creation of at least 2 such alliances.

First within Multiphase metering where a task force of 4 meter manufacturers, namely Fluenta, Framo, Kongsberg Offshore and MultiFluid International and 3 oil companies, Norsk Hydro, Saga Petroleum and Statoil have jointly initiated and conducted an extensive test programme to investigate and assess the performance of the 4 different multiphase meters. To set up such a programme it requires from all parties involved, perhaps especially the manufacturers, a mutual respect to each other and a very strong confidence in their own product.
The other alliance that I would like to emphasize is the recently created GERG-project within ultrasonic gas flow metering where 12 companies, GERG and non-GERG members, have put together their resources and experience from ultrasonic flowmeters. The aim of the project is to make this type of meters conform to the fiscal requirements set by the authorities. Similar project, sponsored by GRI has also been started in th USA.
These 2 projects will contribute to bring us a large step forward in the assessment of multiphase and ultrasonic metering.
If all problems could be solved by a judicious choice of alliances between manufacturers and users it would have been nice. One of the many challenges that we encounter in the process to create powerful alliances is the timing aspect. In general no one is prepared to share its competence and

knowledge in an alliance unless he sees a benefit in the process and is sure that he cannot solve the problem he faces with his own resources.

Development of adequate standards and procedures

It would have been really nice if we could have had access to ready of the shelf solution for all type of metering installation. The reality is that we have to make investigations to look for the most appropriate equipment using our experience, digging into manufacturers brochures, visiting installations in operation and applying the recommendations provided by available standards.

Today the development of new metering technologies proceeds very rapidly and the publication of adequate standards is slipping behind. The needs of the end users are not longer met and the lack of available standards which take into account the latest findings and improvements provided through extensive R&D activities delay to a large extent the implementation in the oil and gas industry of new metering equipment, generating additional and unnecessary workload and costs.

On the other side the preparation of new standards or the revision of the existing ones is a very arduous and expensive task. In addition to the delays due to the administratives procedures involved, we see a certain reservation from the end users to involve themselves. The industry has a very cautious approach to an active participation in the standardisation work and when someone is authorised by his boss to involve himself directly in the basic work, it generally becomes a left hand side work because the topic does have the highest priority in our daily work. Look at your own situation: are you involved and to what extent? It is evident that those companies who dedicates some of their specialists to participate in the standardisation work will inevitably have their views and strategey reflected in the content of the documents being prepared by the standardisation committees.

Look at the present situation of ISO-5167-1 which was partially revised in 1991 using still the original Stolz equation. In 1995 the new findings leading to an improved discharge coefficient equation, better flow conditioning devices and better knowledge of installation effects have not yet been implemented in the standard and we are sticked to the 1991/1980 revision. How could we then benefit from the new knowledge. Should we go for API 2530 which has implemented some of these findings in their revised issue.

Take another example! The very confused situation with respect to uncertainty calculations in flow measurements. We have ISO-5168 which has not been withdrawn, simultaneously with a revised 5168 that the central ISO secretariat in Geneva refuses to publish because it does not comply with the content of a report on uncertainty measurements prepared by a joint Task Force from ISO and OIML among other organisations. This mix-up creates for the users a very confused situation resulting for us here in Norway to the creation of a working group wish shall prepare a code of practice on how to calculate uncertainty in flow measurement.

Now we are preparing a European standard for gas metering stations which will probably be in the public domain from 1997. This standard which is in line with the NORSOK standards in Norway and the CRINE approach in UK will become mandatory to refer to when we request for a quotation.

In that respect we recognise the open mind that the national authorities currently demonstrate by accepting new technologies and new system as long as the operator can document the reliability and the performances of these new systems.

Quality Assurance

Quality Assurance is an ingredient which has been applied to a lot of activities. I think that it has, or if not should have, a central position within metering.

Combining quality and cost efficiency will provide you with the best solution available when designing or operating a metering station. This could be done by looking at the different phases in the life of a metering station. We can clearly identify the following phases:

- conceptual design
- choice of the primary element and secondary equipment
- inspection
- improvement

If we during all these phases ensure to have the best available tools, spending from CFD simulation programs to the footprint mark of THE reference metering station and in addition adequate inspection devices we will achieve high quality to optimal cost in our stations.

I have tried to present to you some of my thoughts on how we, the metering fellows, could contribute to make oil and gas production and transport more efficient in order achieve the economical goal that the oil industry has targetted.

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North Sea FLOW Measurement Workshop 1995

Paper 1: · /

GAS DENSITY INVESTIGATION ON AN OFFSHORE FISCAL GAS METERING STATION

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GAS DENSITY INVESTIGATION ON AN OFFSHORE FISCAL GAS METERING STATION

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SUMMARY

An investigation was initiated to determine the reason for differences in gas density measured by parallel on-line densitometers. Density differences of 0.5% or more had been observed. This paper details an extensive series of tests to resolve the problem, conducted on one meter run during the annual preventive maintenance check. Gas density measurements were made under static and dynamic conditions with pure methane, nitrogen and sales gas. The time delay from point of gas sampling to the point of density measurement was established. The time required for the densitometer to come to temperature equilibrium with the gas stream was investigated. The conditions necessary for the densitometers to produce essentially identical values were determined.

INTRODUCTION

Vibrating element densitometers are commonly used on high pressure North Sea metering systems to measure the gas density for custody transfer. The instruments are installed in accordance with general industry guidelines (Institute of Petroleum or American Petroleum Institute). Often, two densitometers are used to minimize the possibility of shut down if one instrument should malfunction.

During an annual preventive maintenance check of the offshore Tyra East gas metering station operated by Mærsk Oil & Gas, it was observed that the two densitometers on the same gas line would register values that gradually drifted apart. The difference would become large enough to be of concern. There was no evidence of any malfunction of either instrument. It was noted that after performing the vacuum point check on the densitometers the registered values would be in very good agreement.

At a later date a series of tests were conducted on the offshore operating system to determine the source of this problem and the best solution to eliminate it. This paper reports on the results of those tests.

METERING STATION

The gas metering station on Tyra East is equipped with four meter runs. Each meter run is a nominal 273 mm ID and is equipped with an orifice plate fitting. A pressure measuring cell, three differential pressure cells, two in-line densitometers and a platinum resistance thermometer (PRT) are installed on each meter run. Information from all of the installed instrumentation is transmitted to the central control room. In the control room, the information is recorded and displayed. The appropriate information is processed by the flow computer to calculate at 20 second intervals the mass flowrate, the standard volume flowrate and the energy flowrate.

The two densitometers are in a parallel flow arrangement. In normal operation, the gas stream from the sample point after passing through a 9 micron filter is split into two streams, one for each densitometer. There is a 2 micron filter in each line before the gas enters the densitometer. On exiting from the densitometers the gas streams are recombined and the gas is returned to the downstream side of the orifice plate.

The piping arrangement for each densitometer in addition to the filters contains a vacuum connection, a vent connection and numerous block valves. The two parallel piping arrangements are identical except that 1 meter more of tubing was required to connect the second densitometer. All of the components of the piping system are covered with 1 inch of foam rubber insulation.

With this equipment arrangement the density values measured by the two densitometers were generally quite close, but it was noticed that a difference would develop between the two sets of values. On one occasion this difference developed immediately after a meter run was put back into service after a maintenance check as shown in Figure 1. The meter run was cold at the start

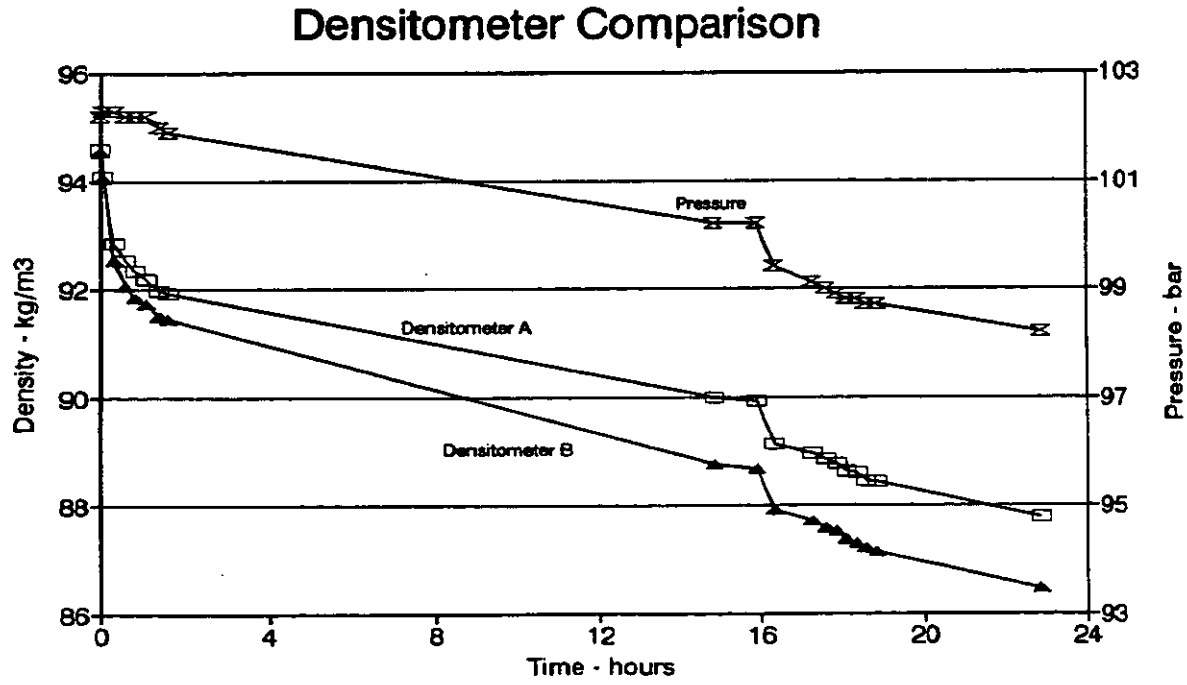


Figure 1

and the change in density over the first hour was thought to be the result of temperature stabilization. The densitometer temperature was not measured but the gas stream temperature was in the range of 30 to 32 degrees Celsius (°C). The discharge pressure from the metering station decreased over the next 24 hours with a corresponding decrease in measured density of each of the densitometers. The difference of about 1 kg/m^3 in the measured density was disturbing as well as the fact that it was increasing with time. Flow through the meter run was discontinued and the vacuum point of each densitometer was rechecked and found to be within range.

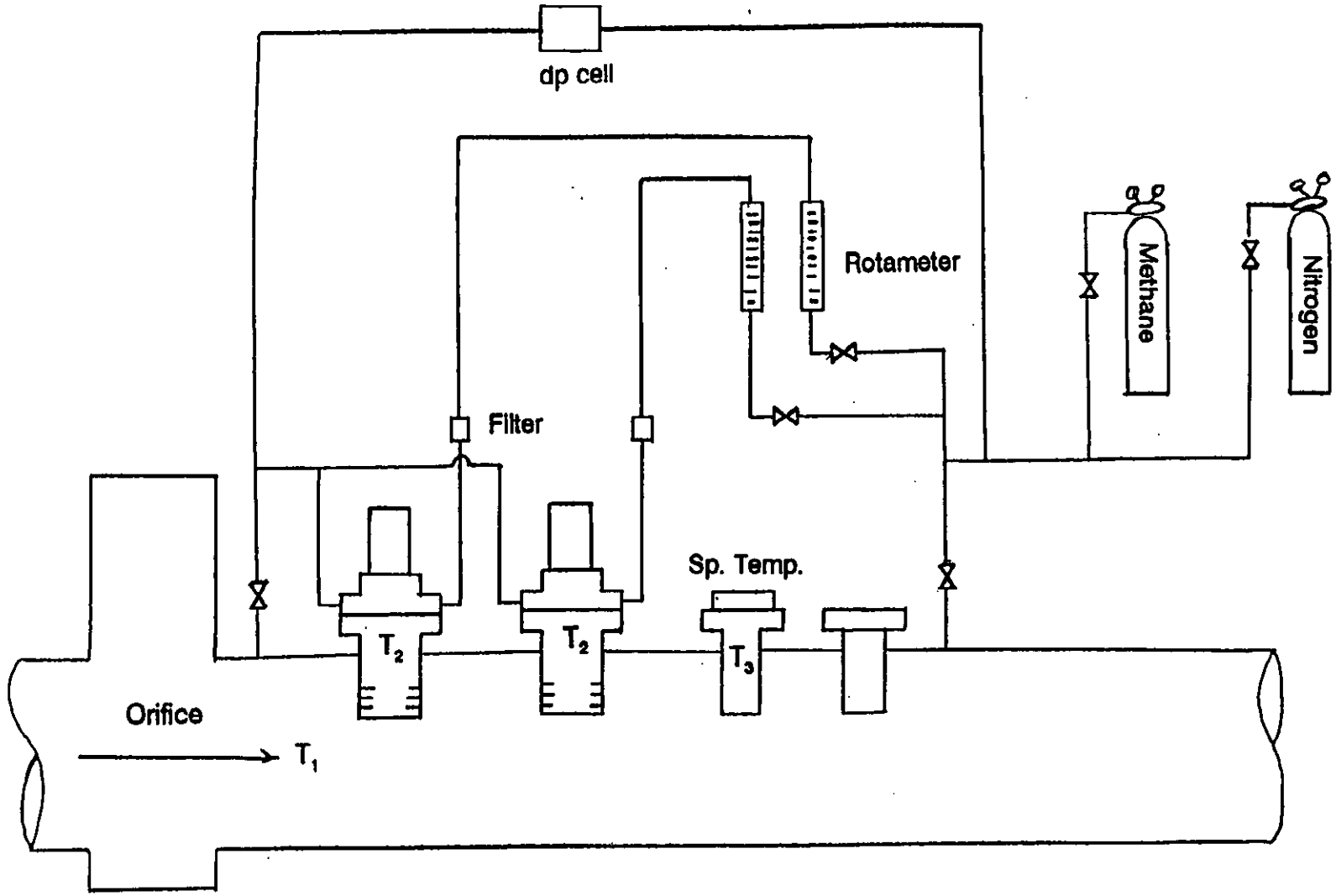
Some rudimentary tests showed that the gas entering the densitometers was essentially at ambient temperature. The gas leaving the densitometers was several degrees warmer. One obvious question was, "What is the gas temperature in the density measurement chamber?" Could the density difference be the result of temperature variation?

TEST PROGRAM

A series of tests were devised to check the operation of the densitometers with nitrogen, methane and sales gas under a variety of static and dynamic conditions. The sample gas system was modified as shown in Figure 2 for these tests. A connection was installed in the gas sample line so that nitrogen or methane could be introduced into the system in addition to normal sales gas. A high pressure rotameter and needle valve was installed to control and balance the flow to each densitometer. A 100 bar test gauge and a differential pressure cell were connected to the sample system for use during some of the tests.

Temperature probes were installed through T fittings into the gas line entering and leaving each densitometer. Initially a single thermocouple was installed in the oil filled well containing the densitometer. After discovering that one of the thermocouples was shorted to the pipeline two thermocouples were attached to each densitometer, one to the bottom of the measuring chamber and one in a cavity on the side of the densitometer.

During the course of the tests, a special insulated enclosure was built around the two densitometers and a portion of the meter run pipeline. A thermocouple was also used to measure the ambient air temperature in the enclosure surrounding the densitometers. The PRT for the flow computer was used as the reference temperature for these tests.



Test Meter Run

Figure 2

TEST RESULTS AND DISCUSSION

A short period of density history was collected on the test meter run before the test equipment was installed. This data shown in Figure 3 would serve as a baseline for comparison with the test

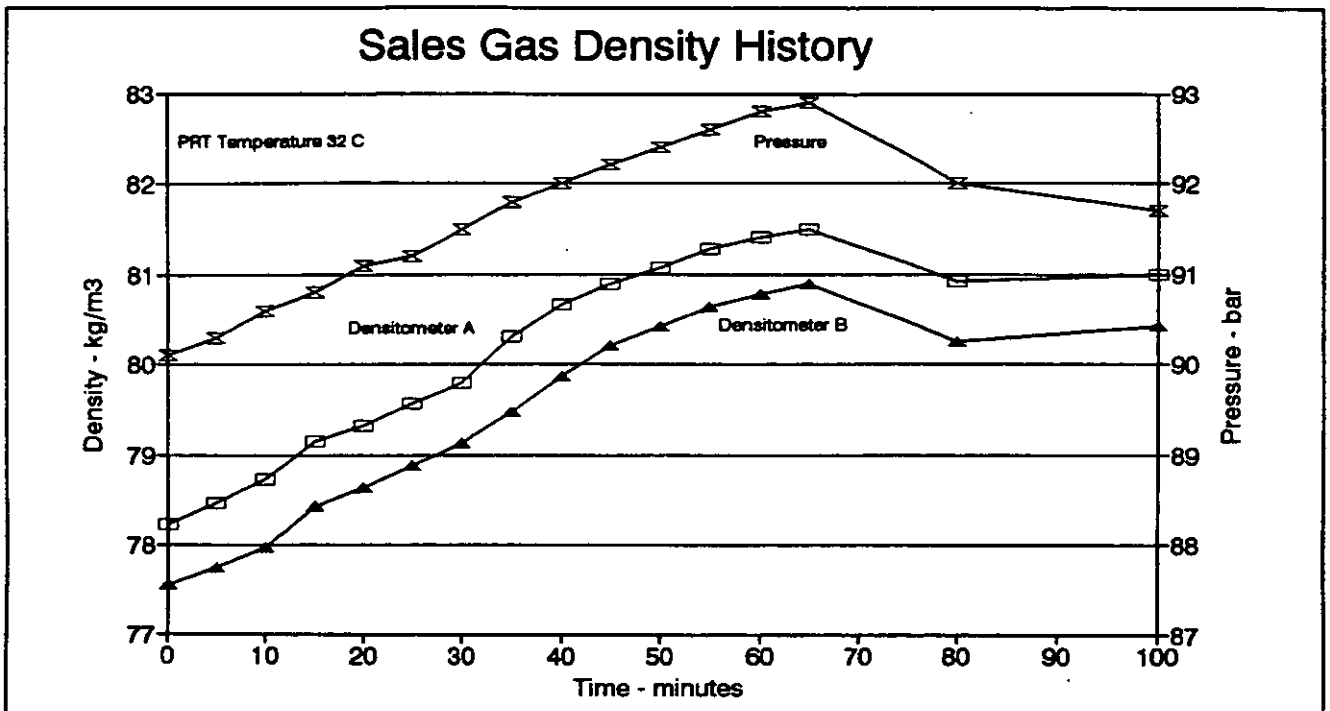


Figure 3

results. There was a reasonably consistent difference of about 0.6 kg/m^3 between densitometer A and B. Densitometer A was the first instrument downstream of the orifice plate. These results were consistent with the previous observations.

To assure that the densitometers were measuring correctly and that the installation in the pipeline was not contributing to the measurement difference, several tests with pure nitrogen and methane were carried out with the sample system isolated from the main pipeline. The measured density values for methane as a function of pressure for densitometers A and B are plotted in Figure 4. The two agreed within about 0.02% of full scale. The methane density measured at 50 and 100 bar and 17.4°C were 37.25 and 80.31 kg/m^3 respectively. Values interpolated from the National Bureau of Standards[1] (NBS) data for these conditions are 36.56 and 79.72 kg/m^3. Considering that these tests were done on an operating offshore platform and the possibility of error in the pressure and temperature measurements, the deviation from the NBS data is considered very reasonable.

The measured density for methane also agreed quite well with the value calculated for each pressure and temperature condition using a gas density calculation program from AGA 8[2].

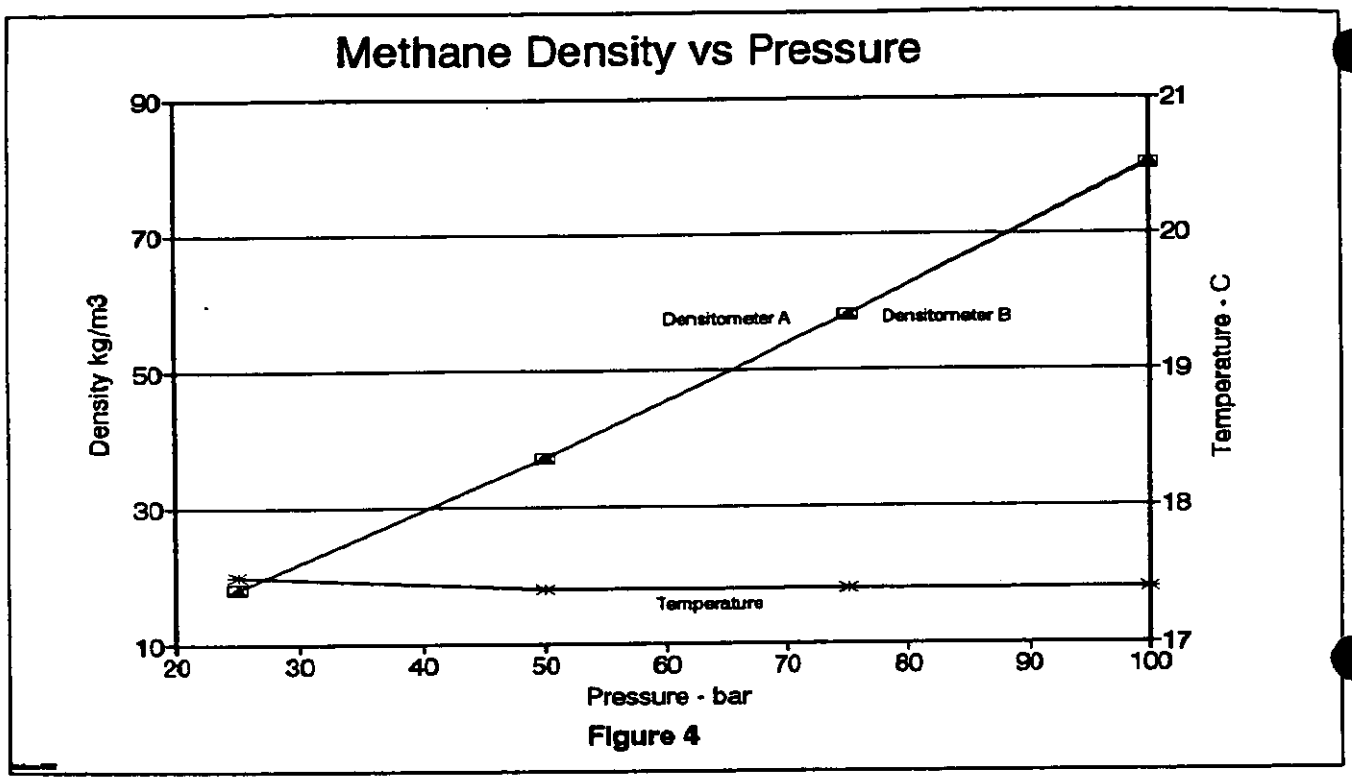


Figure 4

A similar test was performed with nitrogen and the results are shown in Figure 5. Again, there was good agreement of the measured values with values calculated from AGA 8.

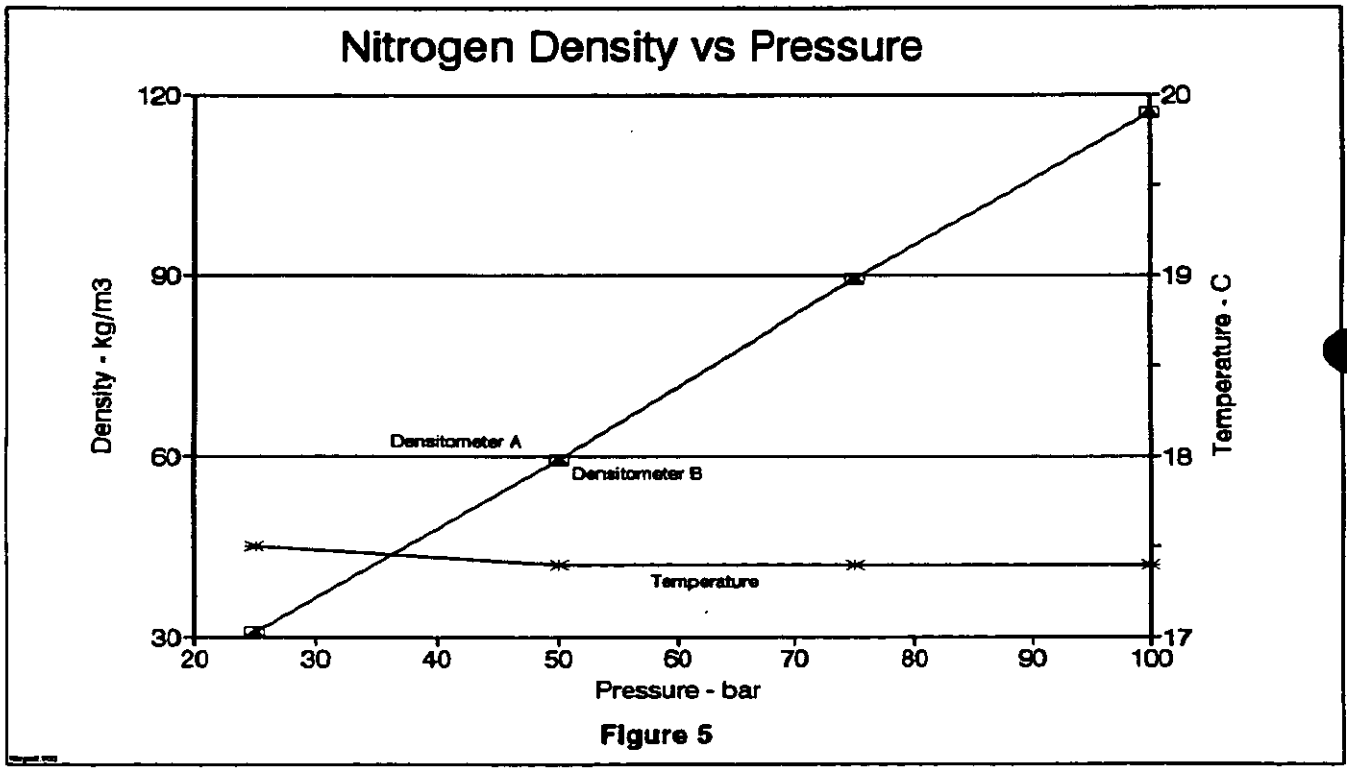


Figure 5

The experimentally measured nitrogen density at 50 and 100 bar and 17.4°C were 59.47 and 117.04 kg/m³ respectively. These values are in line with values interpolated from NBS[3] data of 58.35 and 116.04 kg/m³ taking into account the possibility of error in the temperature and pressure measurements. While this was not an attempt to calibrate the densitometers, the field installed densitometers were judged to be fairly accurate.

The stability of the densitometers with time was tested by pressurizing and isolating the sample system. When the nitrogen supply valve was closed completely isolating the sample system, the density decreased indicating that a small leak existed in the sample system. The small volume of the sample system made the leak very noticeable. Attempts to locate the leak were unsuccessful. Therefore, to negate the effect of the leak, the sample line discharge valve was opened to the meter run to provide a large reasonably constant pressure reservoir. The densitometer stability with time is shown in Figure 6. The first four data points show the effect

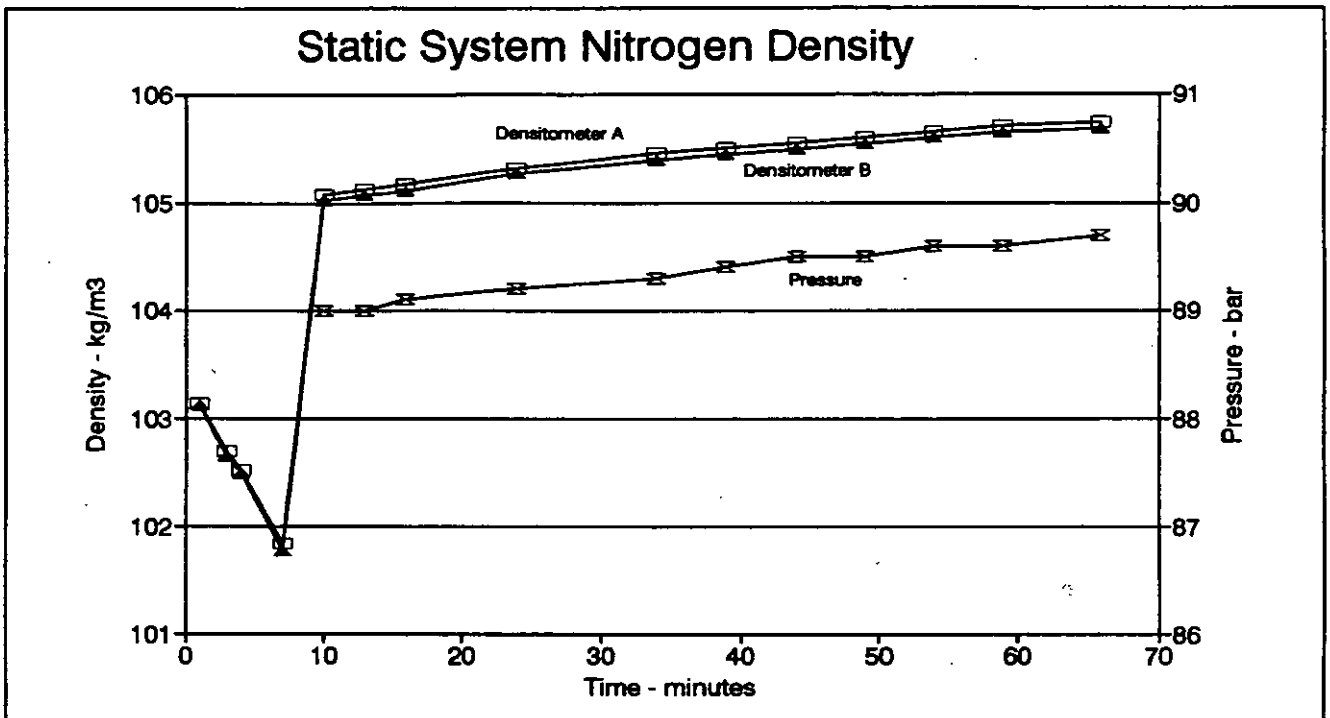


Figure 6

of the leak. The sample system was open to the meter run for the remaining points. The meter run was isolated by block valves, but the observed pressure increase indicates that some minor leakage was occurring through the block valves. The PRT temperature increased during the test from 17.1°C to 17.4°C. This increase in temperature would not account for the pressure change observed in the meter run.

The two densitometers track very well and have a small constant difference in measured density of about 0.05 kg/m³. The increase in density with time is as expected with the increase in the pressure. The 0.3°C temperature increase would alter the nitrogen density in the order of 0.12%.

A stability test with methane was also conducted with the sample system open to the mainline pressure. The pressure and density data are shown in Figure 7. The densitometers tracked very

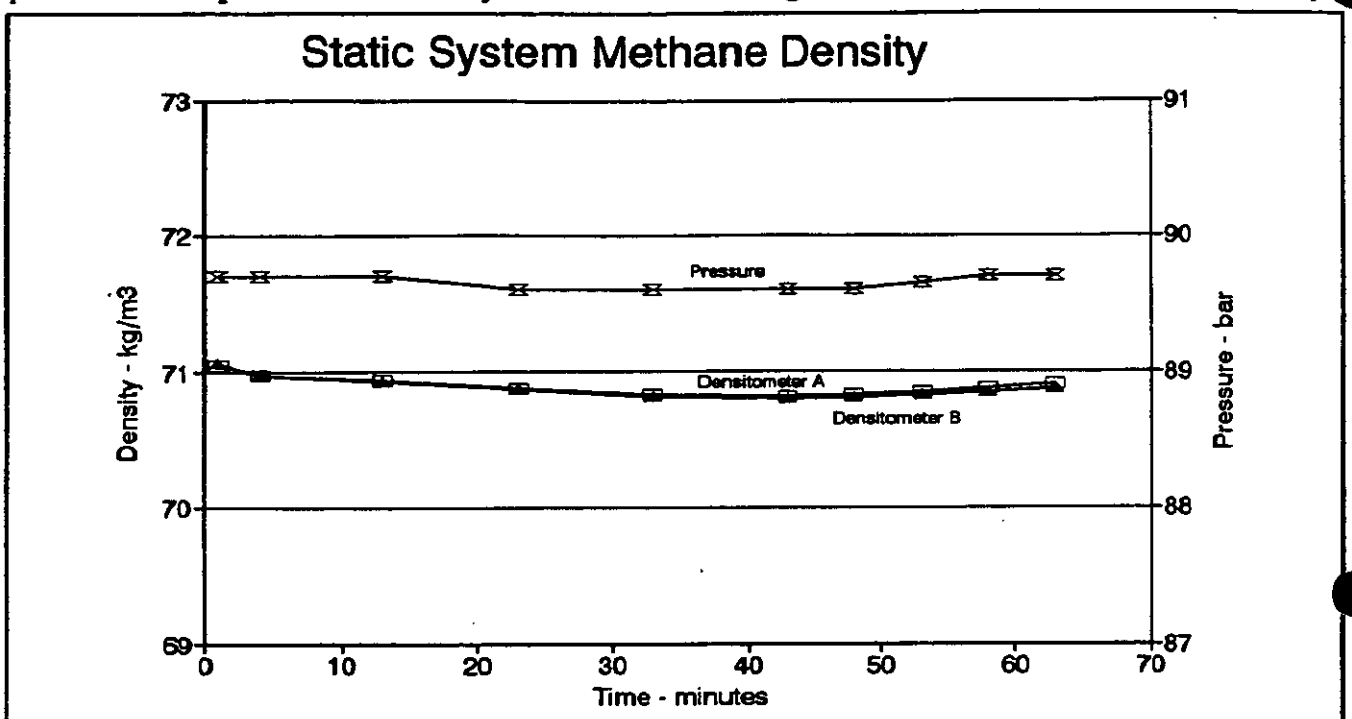


Figure 7

well over the time period with a very small difference of about 0.02 kg/m^3. The pressure decreased by 0.1 bar during the first part of the test and then increased by that amount towards the end. The temperature increased from 17.5°C to 17.9°C during the test. The change in temperature and pressure will account for the density history. The static tests with nitrogen and methane show that the two densitometers are accurate within the limits of the field check and measure essentially identical values under identical conditions.

Two tests were conducted (one each with nitrogen and methane) to observe the effect of gas flow rate on the densitometers. The rotameters and needle valves were used to adjust for equal flow through each densitometer, but the total flow through the sample system was controlled by the differential pressure across the system. The test were conducted at a pressure of approximately 100 bar on the system.

The results of the test with nitrogen are shown in Figure 8. The two densitometers had a constant difference in the density value for nitrogen of about 0.1 kg/m^3. The density values increased with increasing gas flow through the densitometer, consistent with information supplied by the manufacturer. The nitrogen gas entering the densitometers was below ambient temperature because of expansion from the high pressure cylinder. The gas exiting the densitometers was warmer, but not at the temperature registered by the PRT sensor. It is postulated that the densitometers were unequally cooled by the extensive nitrogen flushing of the

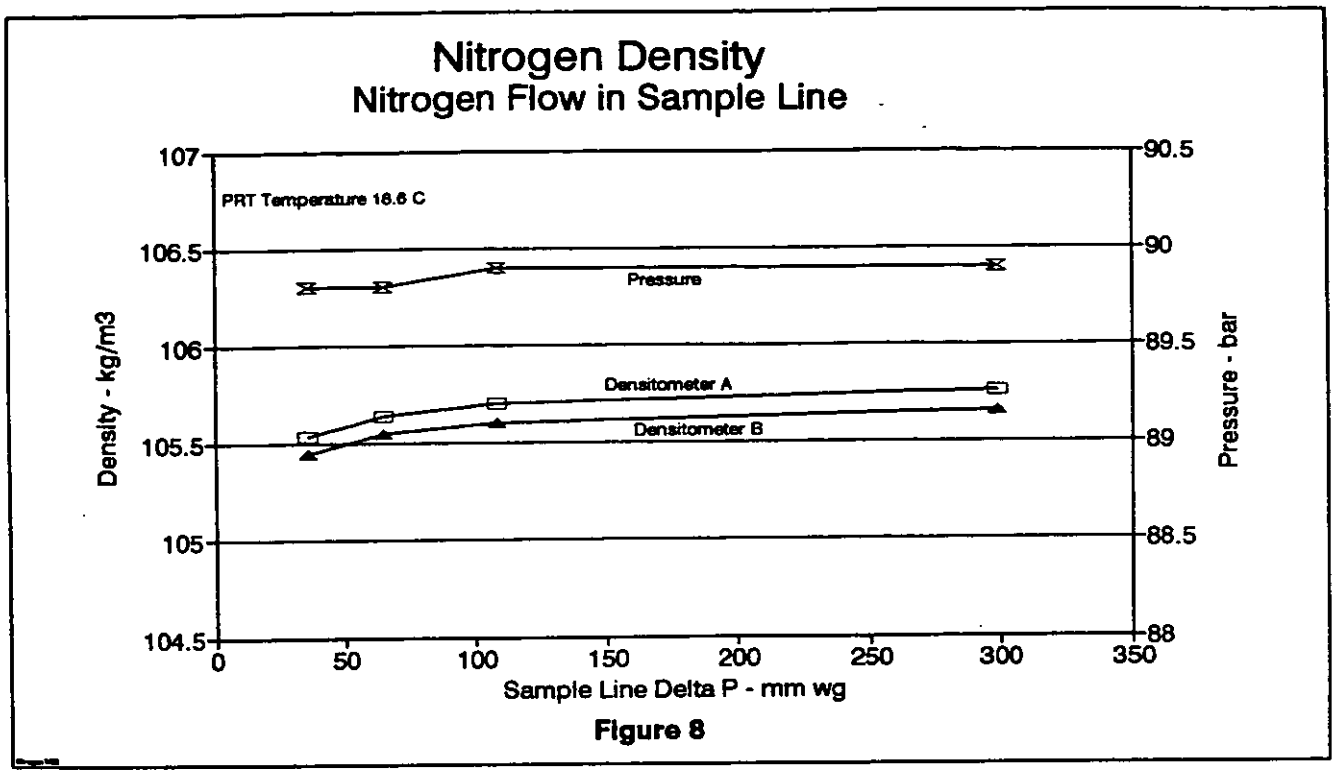


Figure 8

system prior to the flow test. A difference in densitometer temperature would result in a difference in the measured density.

Flow tests with methane were carried out and the results are shown in Figure 9. The

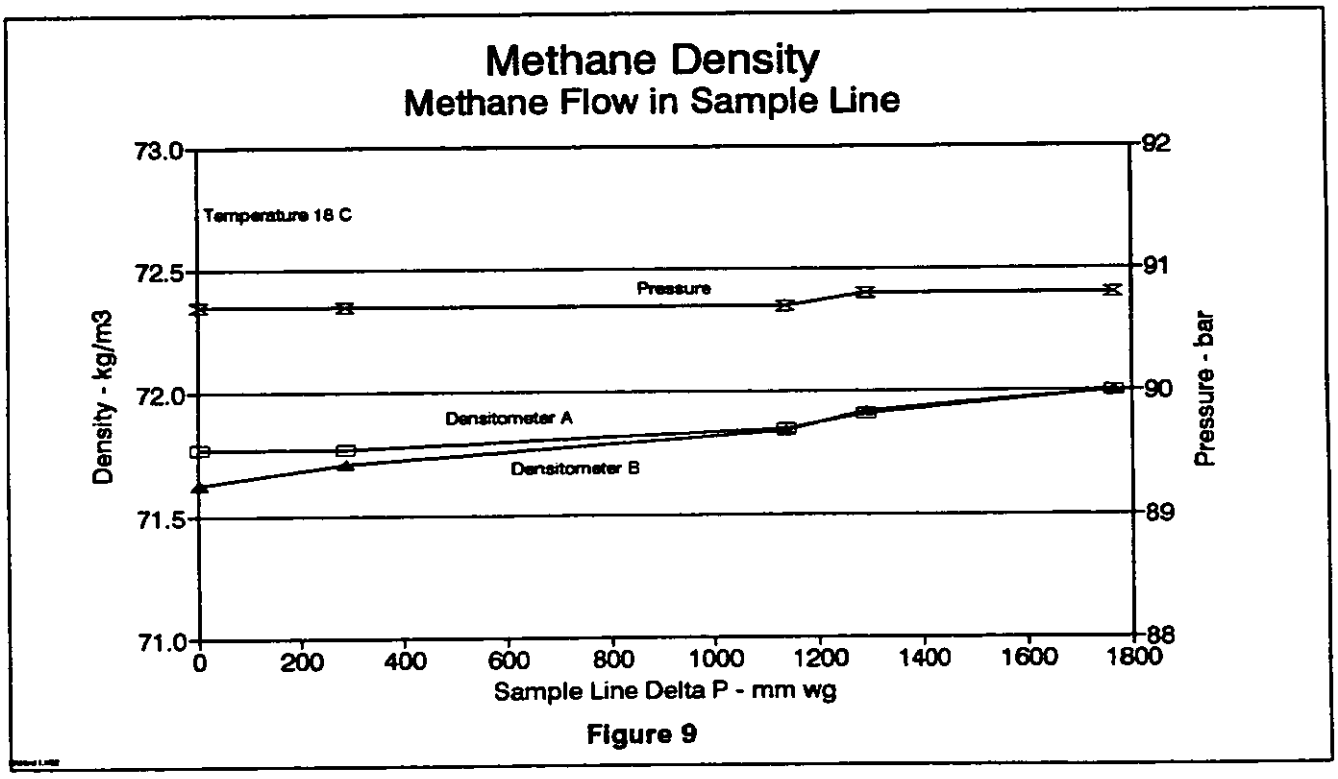


Figure 9

temperatures of the densitometers were unequal and lower than the PRT sensor temperature. This temperature difference is probably responsible for the initial gas density difference of about 0.15 kg/m³. As the flow rate increased the density difference decreased presumably as the measurement conditions became comparable. A slight increase in density is observed with increased flow rate. The results of these tests were not as precise as the nitrogen tests, but it is confirmed that the densitometers produce essentially identical results with gas flow and as expected the density increases with increased flow rate.

The response of the densitometer to temperature change, as a result of flow in the meter run, was the objective of the next test. The densitometers were purged with methane, isolated from the meter run and allowed to stabilize. Sales gas flow was started in the meter run and the results are shown in Figure 10. The temperature of the PRT sensor rose very quickly and stabilized at

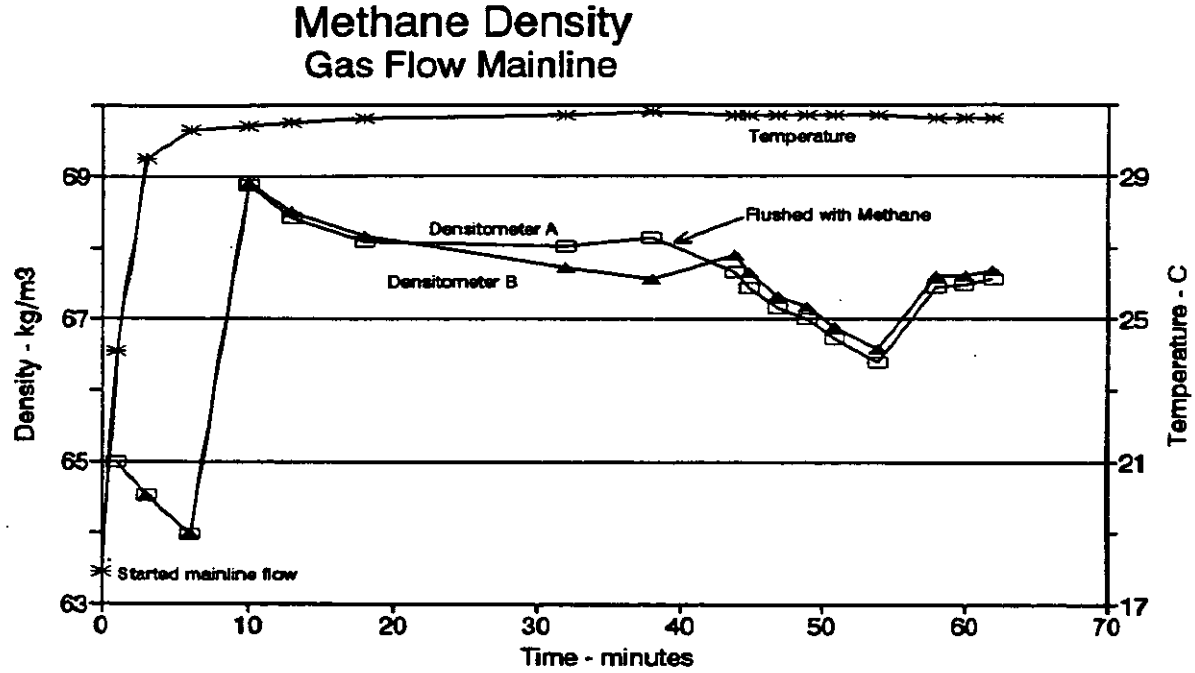


Figure 10

about 31°C. The two densitometers measured nearly identical but decreasing values for the first six minutes. The decrease in density is the result of the densitometers warming and the persistent leak in the sample system.

Prior to the 10 minute mark, the sample system discharge valve to the meter run was opened to maintain a more constant pressure thereby, producing an offset in the measured density. Densitometer B showed decreasing values up to the 40 minute mark as the densitometer temperature equalized with the meter run. Densitometer A also showed a decrease in density as it became warmer, but then the measured density increased slightly as a result of the leak permitting sales gas with its higher density to mix with the methane. Just after the 40 minute mark, the sample system was purged with methane and isolated once again. The measured values were within 0.2

kg/m³ or less and decreasing as the pressure dropped because of the leak. The discharge valve to the meter run was opened again at about the 55 minute mark. These results illustrate the sensitivity of the densitometers to changes in pressure, gas composition and temperature.

Inlet and outlet gas stream measurements on the densitometers indicated that the one inch of foam rubber was not adequate insulation as the temperature of the densitometers were not the same as the temperature measured by the PRT sensor. Therefore, a special insulated enclosure was assembled around the two densitometers and a portion of the meter run to provide a more uniform temperature environment. After stabilizing for over 12 hours, the pressure, density and temperature for the meter run are plotted in Figure 11 for a twenty five hour period. This figure

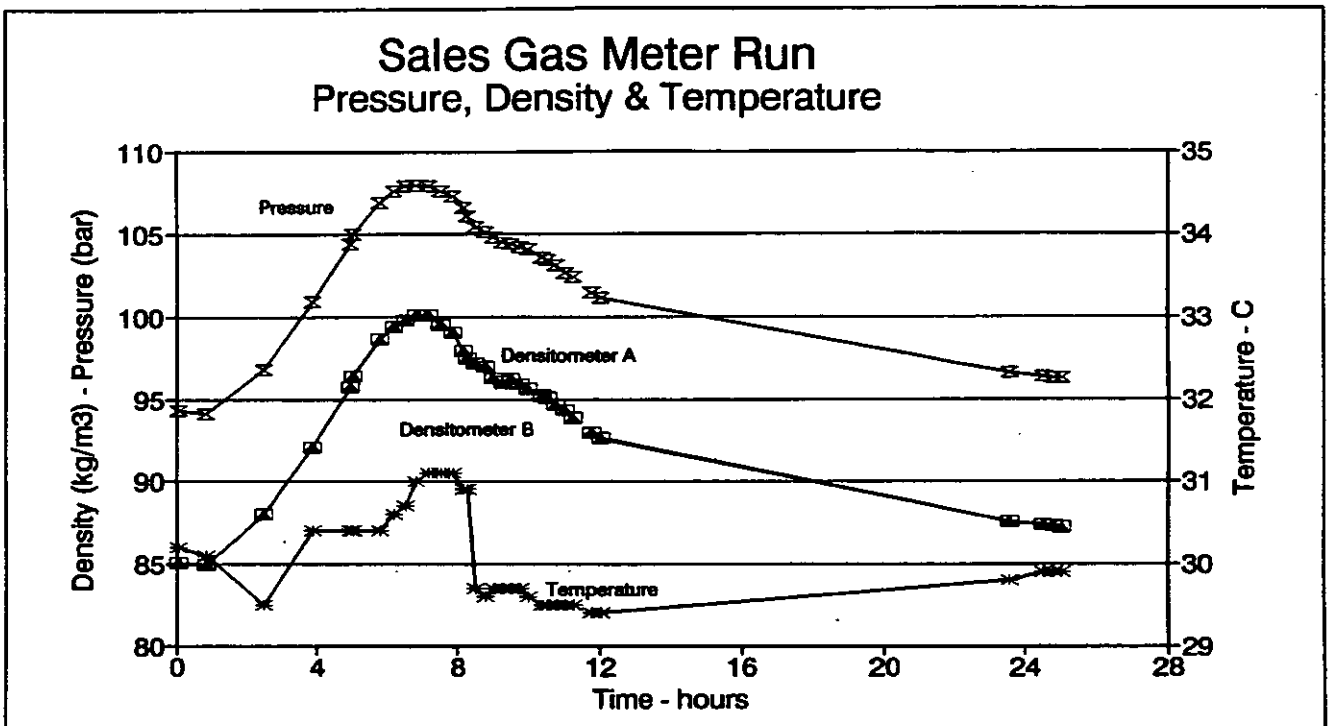


Figure 11

demonstrates that very often in field operations changes in pipeline delivery pressure will have a greater overall effect on the measured density than temperature variations. The density difference during this time period averaged 0.02 kg/m³. It is evident from this figure that the two densitometers track very well in this dynamic situation. This figure illustrates the importance of maintaining the instruments at the same flow and temperature condition.

The sales gas composition is measured at 20 minute intervals by a chromatograph. Using the chromatograph analyses, sales gas densities were calculated by AGA 8 over a six hour period for the temperature and pressure conditions recorded in Figure 11. The calculated and measured densities are compared in Figure 12. The calculated densities compare very favorably with the measured density. The measured density would be expected to be slightly greater since the calculated densities are based on a maximum molecular weight of hexane whereas the measured sample actually has a small fraction of higher molecular weight components.

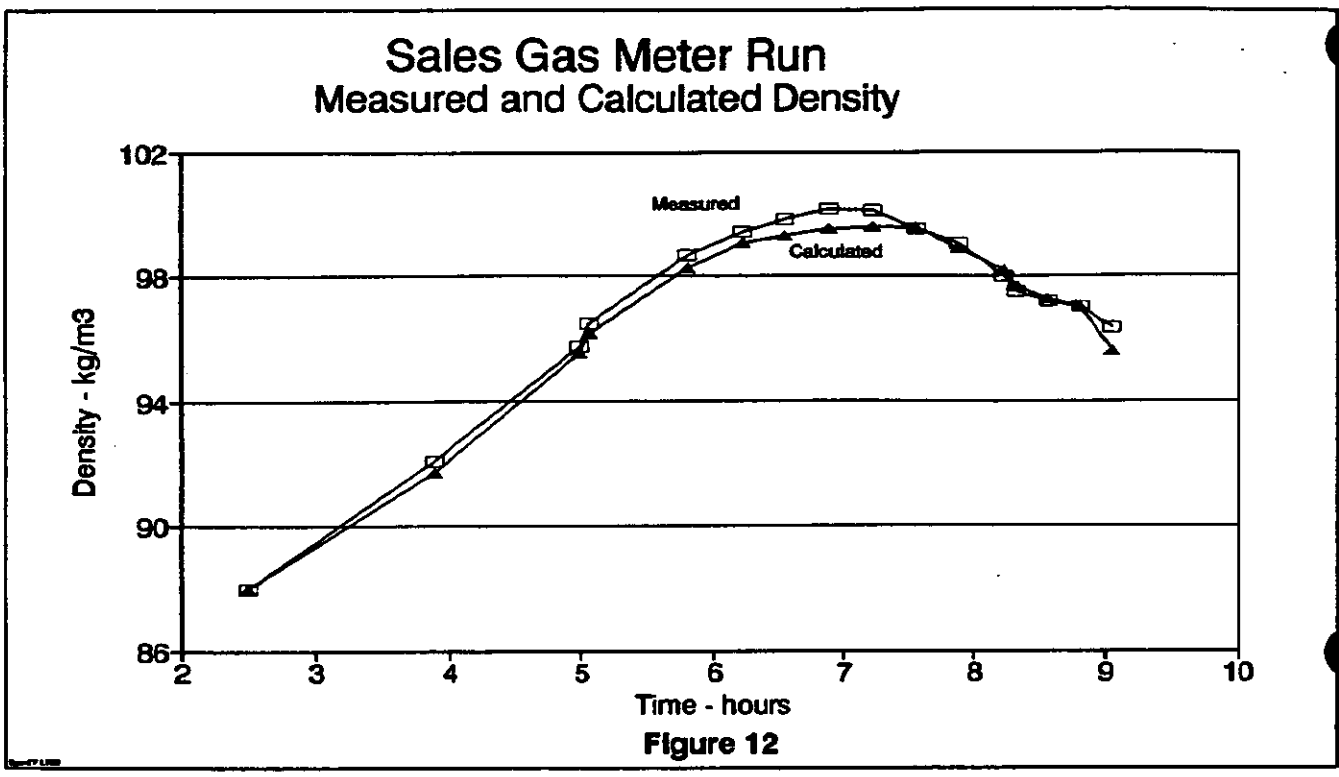


Figure 12

There are always slight changes in the chromatograph composition of the sales gas from one analysis to the next. A series of data points were calculated to determine the effect of using a constant gas composition for the density calculation. The gas density was calculated for each pressure and temperature condition using the first gas composition and these are compared with the densitometer measurements in Figure 13. There is no doubt that even small variations in gas composition has a noticeable effect on the measured density.

The length of the lines from the sample point to the densitometers and the relatively low flow rate in the sample lines will result in a lag between the volume measurement of the sales gas and the density measurement of that gas. This lag time is not a constant since the flow rate in the sample system is dependent upon the differential pressure across the orifice plate which varies from about 1000 mm water gauge (wg) to over 3000 mm wg.

The lag time was determined by measuring the time required for sales gas to displace methane from the sample system. One test is shown in Figure 14. The displacement was started at the 10 minute mark and was completed at about the 70 minute mark. The lag time is about 60 minutes. The hump in the first part of the displacement curve was completely unexpected and was considered to be the result of contamination by sales gas left in a dead end connection on the sample system.

The displacement of the two curves in Figure 14 suggests that either the flow rate was different into the two densitometers or the volume of the lines differed. This test was performed before

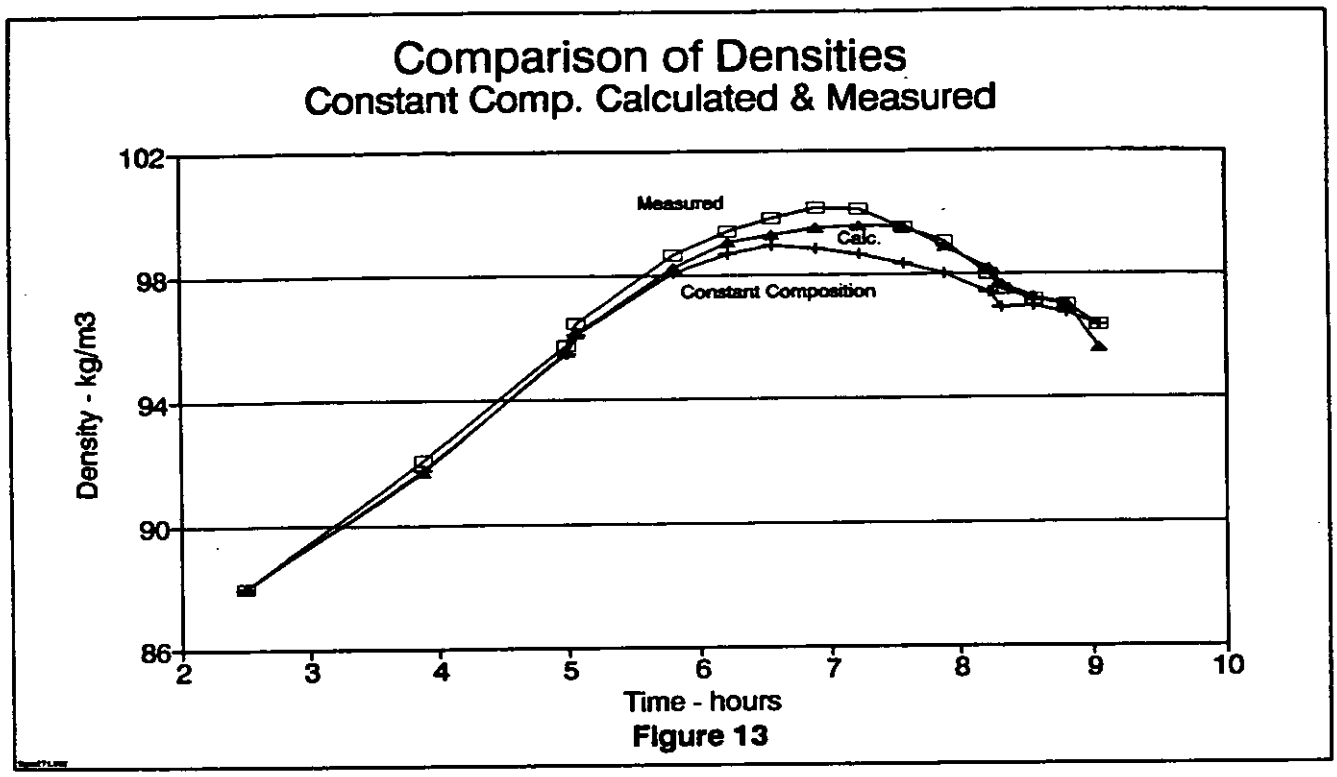


Figure 13

the special enclosure was built around the densitometers. A difference in densitometer temperatures could have contributed to this result. The displacement of the curves probably is a combination of all these factors.

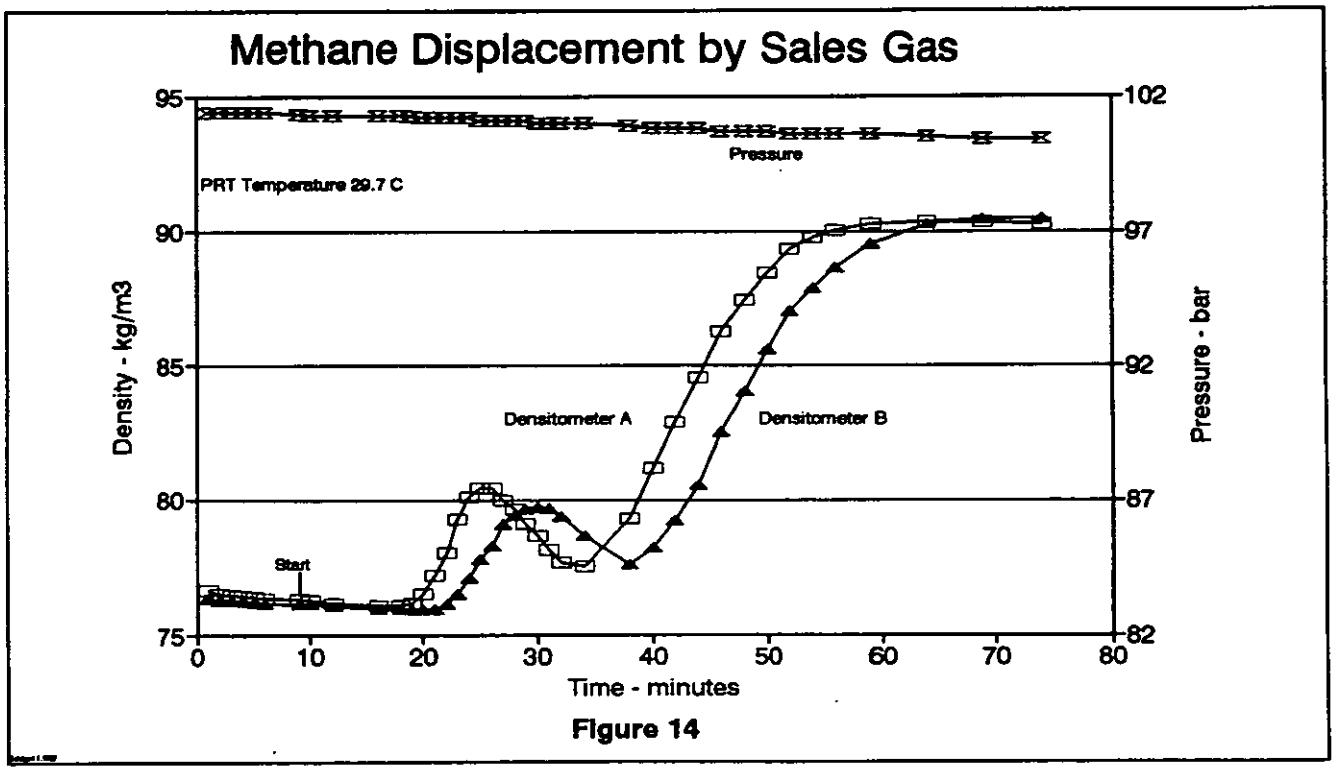


Figure 14

The methane displacement by sales gas test was repeated several times after the densitometers were in the special enclosure. More attention was paid to details of the displacement in an

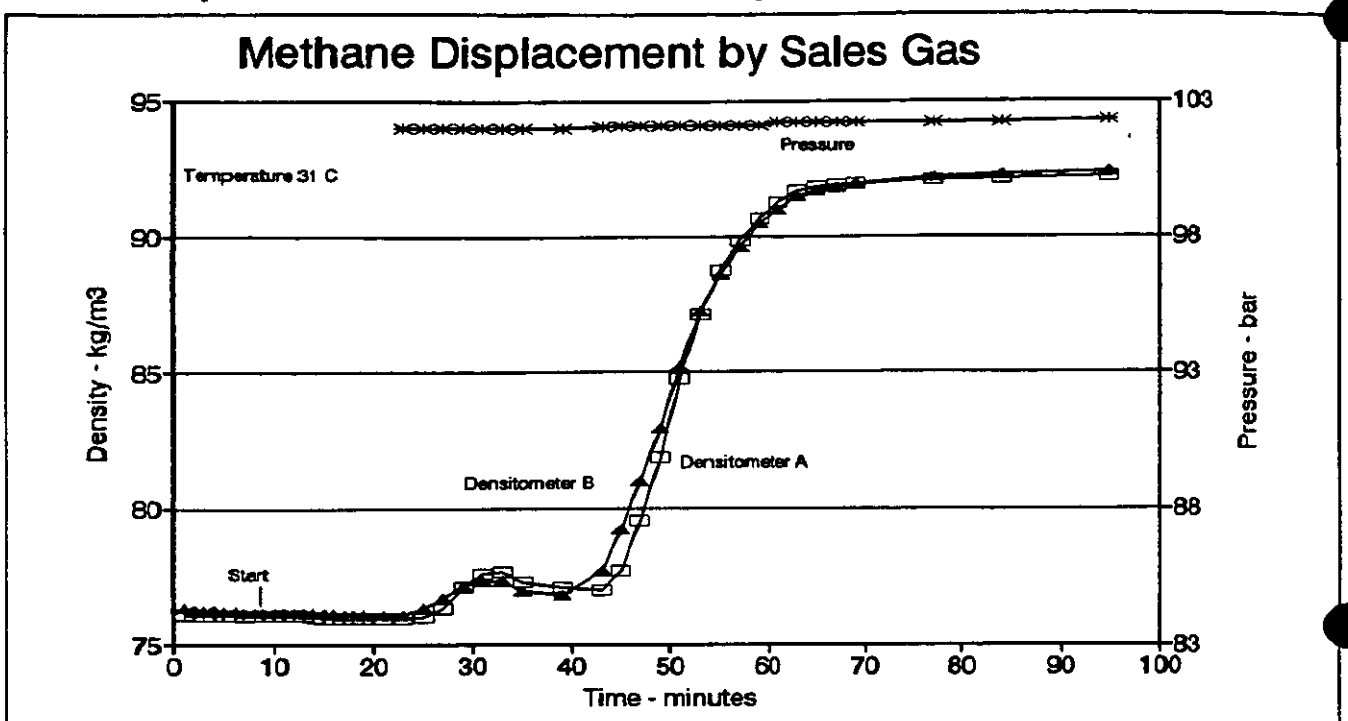


Figure 15

attempt to determine the cause of the hump in the first part of the displacement curve. Two results are shown in Figures 15 and 16. There is agreement between the values of the two

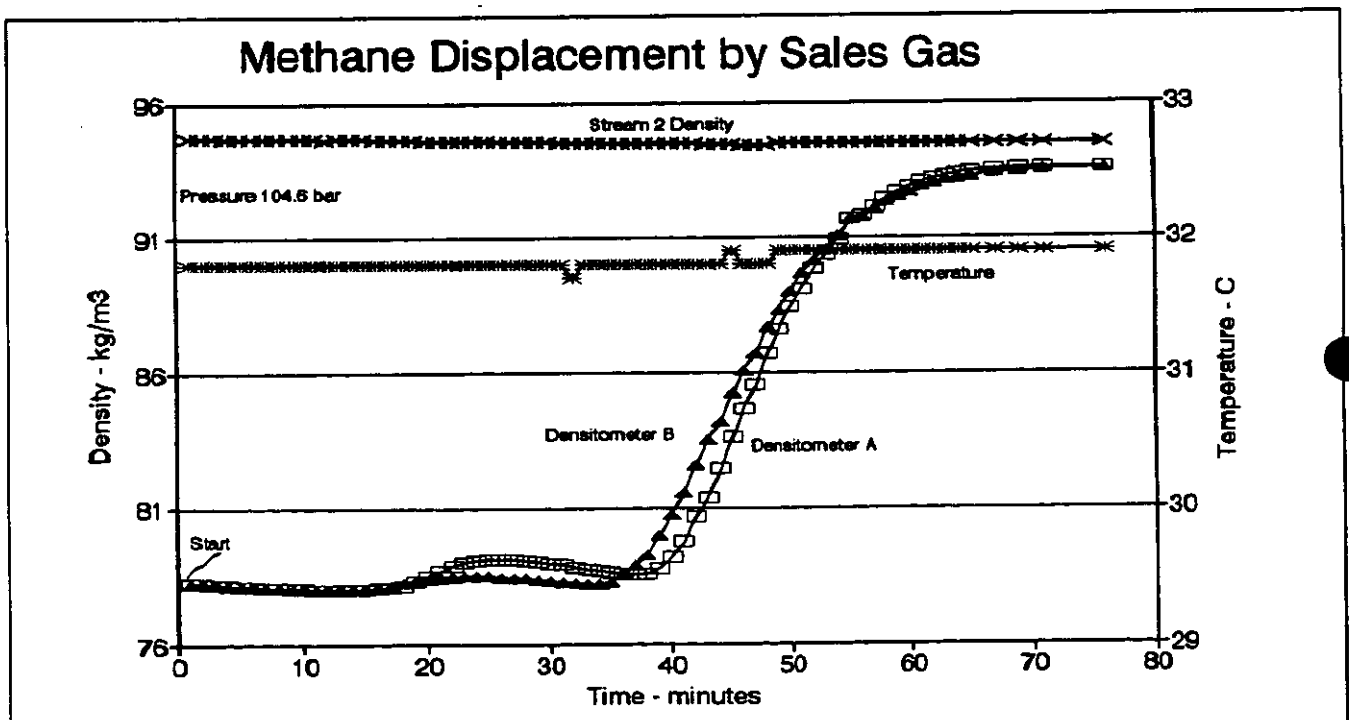


Figure 16

densitometers prior to the start and upon completion of the displacement, but there is a shift in the curves during the transition portion of the displacement. Extensive purging of all parts of the sample system decreased, but did not remove the hump from the displacement curve. One possible explanation for this phenomenon is that some material was absorbed onto the metal filters from the sales gas during normal operation of the sample system and was desorbed into the methane when the pure methane was introduced into the sample system.

In Figure 16 (the last displacement test) the density of an adjoining meter run is recorded and plotted. Two factors were responsible for the difference between the test meter run density and stream 2 meter run density at the end of the test. First there was a small difference in the differential pressure across the orifice plates and secondly , the densitometers on the stream 2 meter run were not as well insulated and therefore at a slightly lower temperature.

It is assumed in the gas flow calculation that the temperature measured by the PRT sensor is the temperature of the gas in the densitometer. In some of the previous tests, it has been shown that apparently the temperature in the densitometer measuring chamber is not the PRT temperature.

To get a more accurate measure of the densitometer temperature, two thermocouples were fixed to the outside of the instrument as shown in Figure 17. The thermocouple on the bottom was

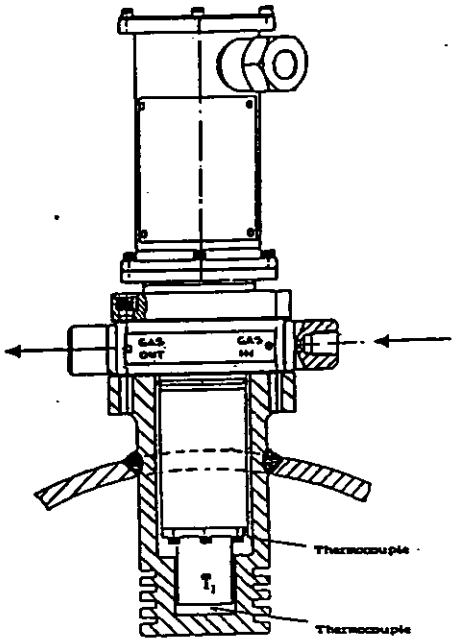


Figure 17

Gas Density Transducer

held in place with tape. The side thermocouple was inserted in a small hole on the body of the densitometer and taped in place. The instruments were reassembled inside of the insulated

enclosure. The meter run was completely isolated and allowed to stabilize at ambient temperature which was about 13°C.

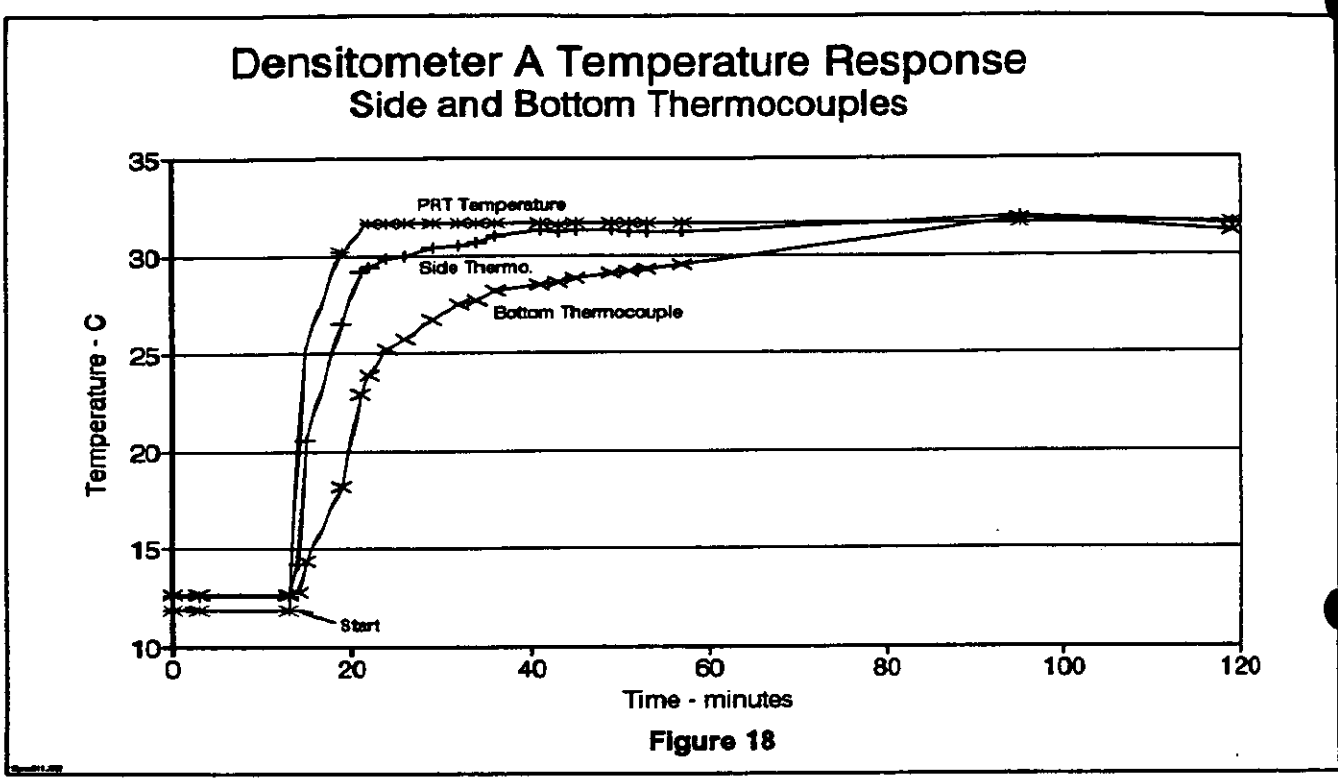


Figure 18

After about 18 hours, flow was started in the sample system and through the mainline. The PRT sensor temperature very quickly stabilized at about 32°C as shown in Figure 18 and Figure 19

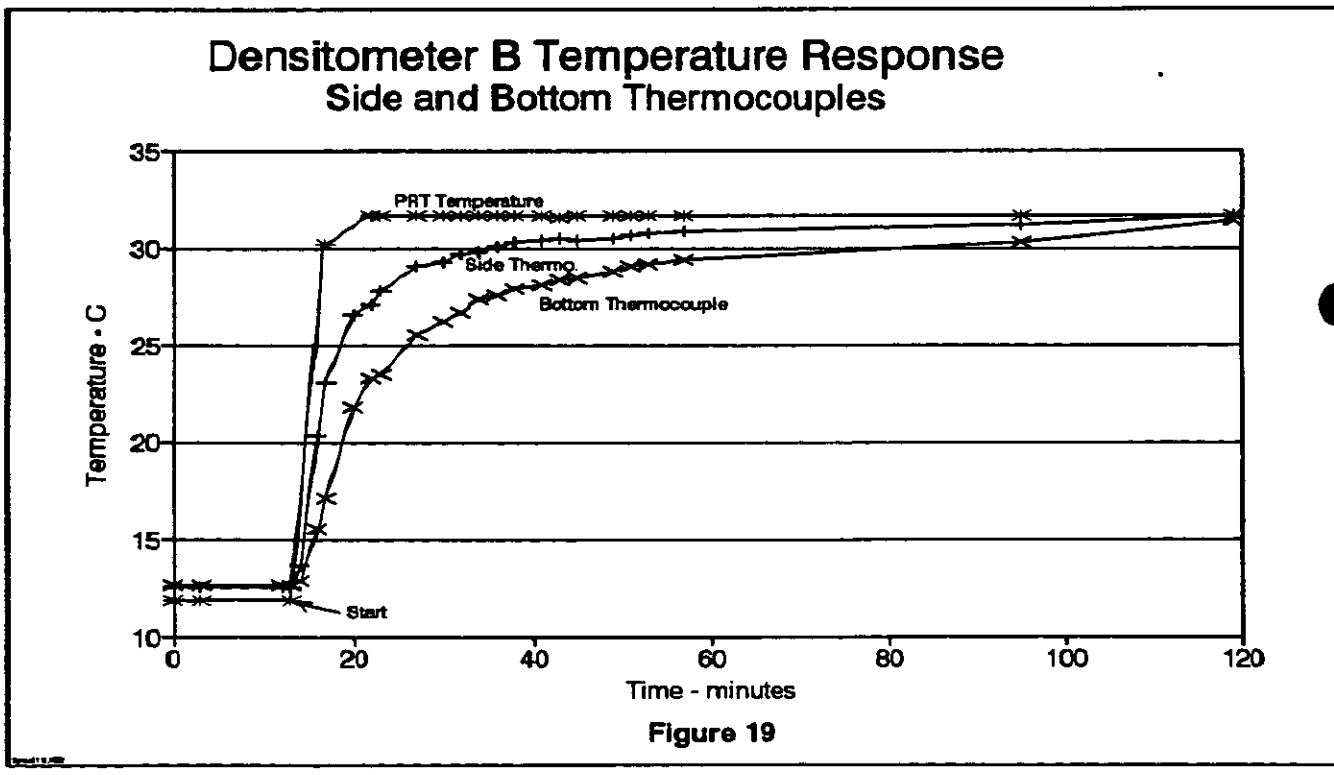


Figure 19

for densitometer A and B respectively. The side and bottom thermocouples took considerably longer to reach the same temperature as the PRT sensor. Since the side and bottom measurements are on the outside of the density measurement chamber, the chamber temperature could not be any higher. The well in which the densitometer is mounted is filled with oil and the heat transfer must be through that medium. The fact that for the side mounted thermocouple, the heat transfer is taking place across a much shorter distance, may explain why that thermocouple warms up faster than the bottom thermocouple. In addition to a less efficient heat transfer the bottom of the densitometer, which is the measuring chamber, may be cooled (heat is being removed) by the flow of gas through the densitometer. It can be concluded that the measuring chamber of the densitometer may take at least two hours to come to temperature equilibrium with the gas stream even in a well insulated system.

A plot of sales gas density history is shown in Figure 20 for the test meter run after the stream

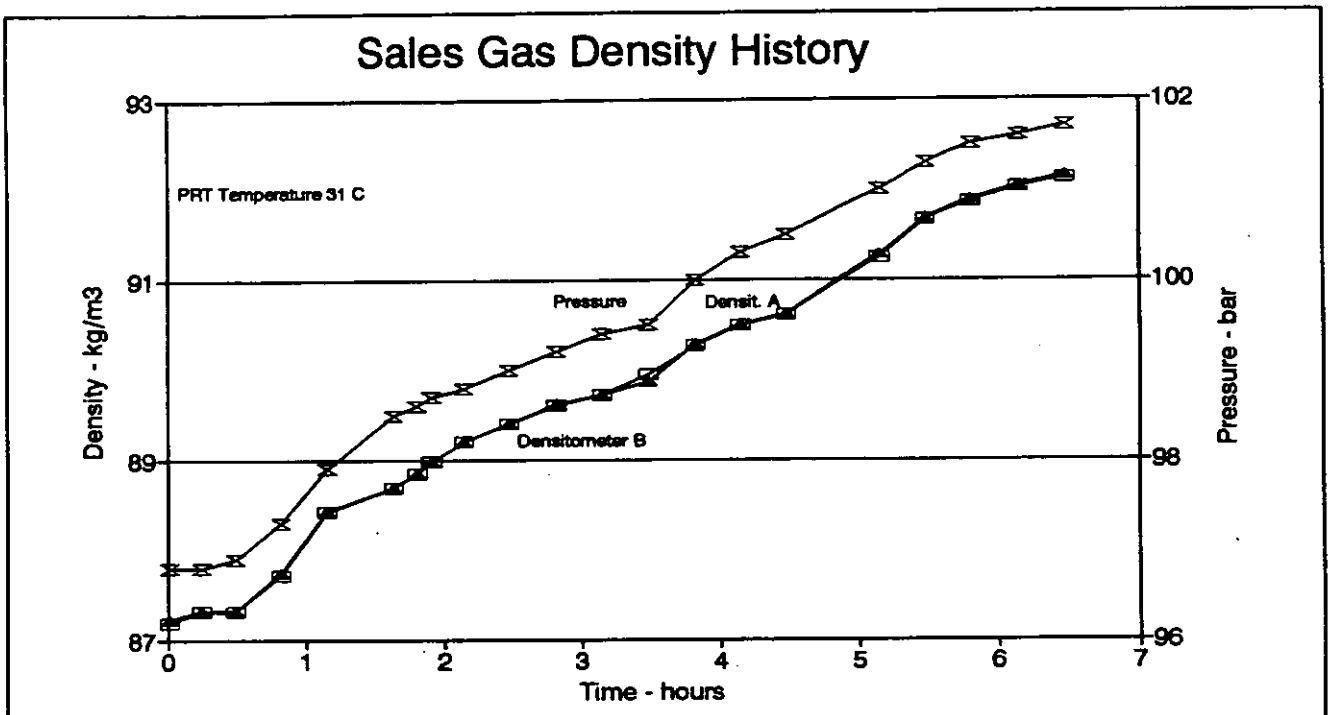


Figure 20

had been in operation for about a week. The two densitometers were measuring on average within 0.01% of full scale. This demonstrates that with similar flow rates and in a temperature stable environment the two densitometers will measure essentially the same value.

CONCLUSIONS

Based on the preceding tests it can be concluded that:

1. Calibrated densitometers on the same meter run will measure the same density under similar conditions of pressure, temperature and sample flow rate.

2. The PRT temperature sensors respond very quickly to temperature changes of the sales gas in the meter run.

3. Starting from ambient temperature, the temperature in the densitometer measuring chamber may take at least two hours or more to stabilize to the line temperature.

4. The density measurement lags behind the volume measurement by about one hour in this system.

5. There is a slight increase in measured density with increased gas flow through the densitometers in this system.

6. The measured density will vary between meter runs because of small differences in differential pressure across the orifice plates.

7. Differences in measured density on the same stream are the result of temperature and flow rate differences in the densitometers.

8. With an enclosure surrounding the densitometers and pipeline to provide good temperature equilibrium, densitometer accuracy of 0.2% should be possible.

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[3] Hilsenrath, J. et al. - "Tables of Thermodynamic and Transport Properties of Air, Argon, Carbon Dioxide, Carbon Monoxide, Hydrogen, Nitrogen, Oxygen and Steam" Pergamon Press, New York · Oxford · London · Paris 1960

Main Index

North Sea FLOW Measurement Workshop 1995

Paper 2:

INTRODUCING THE COMPACT PROVER IN BRAZIL BY COMPARISON TESTS WITH A CONVENTIONAL ONE

1.2

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NORTH SEA FLOW MEASUREMENT WORKSHOP 1995

INTRODUCING THE COMPACT PROVER IN BRAZIL BY COMPARISON TESTS WITH A CONVENTIONAL ONE

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Summary
In December 1993, the PETROBRÁS Paulínia Refinery acquired a Compact Prover for calibrating LPG turbine meters, replacing an old existing conventional prover. The compact prover were installed in parallel with the conventional prover to conduct comparative performance tests during transfer of custody. These tests were performed in accordance with API Measurement Standards, from November 1994 to February 1995. The Meter Factor obtained from the two provers for the same reference turbine showed good approximation results. The compact prover was approved in tests by PETROBRÁS and it is being used by the Paulínia Refinery (REPLAN) for calibrating LPG turbine meter.

I - INTRODUCTION

PETROBRÁS is the governmental monopoly company that explores and refines petroleum in Brazil. It refines 1.4 million bbl/d of crude oil, billing around 20 billions US dollars per year. Brazil's largest refinery is Paulínia Refinery - REPLAN, located in the city of Paulínia - SP. REPLAN crude oil load is 300,000 bbl/d and main products are: gasoline, diesel and LPG.

Through PETROBRÁS/REPLAN, an average of 50,000 tons/month of Liquefied Petroleum Gas (LPG) are sold. The international price of this product fluctuates under US $ 200.00/ton. This inventory represents an annual billing on the order of US $ 120 million. Uncertainties or variations close to 1.0 % in the measurement of LPG sales from the refinery, represent to PETROBRÁS US $ 1.2 million that can be lost annually, depending on the direction of the error of the measuring instrument.

Instruments and equipment, that measure and record as faithfully as possible the inventory of products sold by the refinery, are grouped in the same area, forming the systems called by PETROBRÁS EMEDs (Portuguese abbreviation for "Measurement Station") which are composed of piping, filters deaerating vessels, flowmeters, as well as indicators, totalizers, and so on.

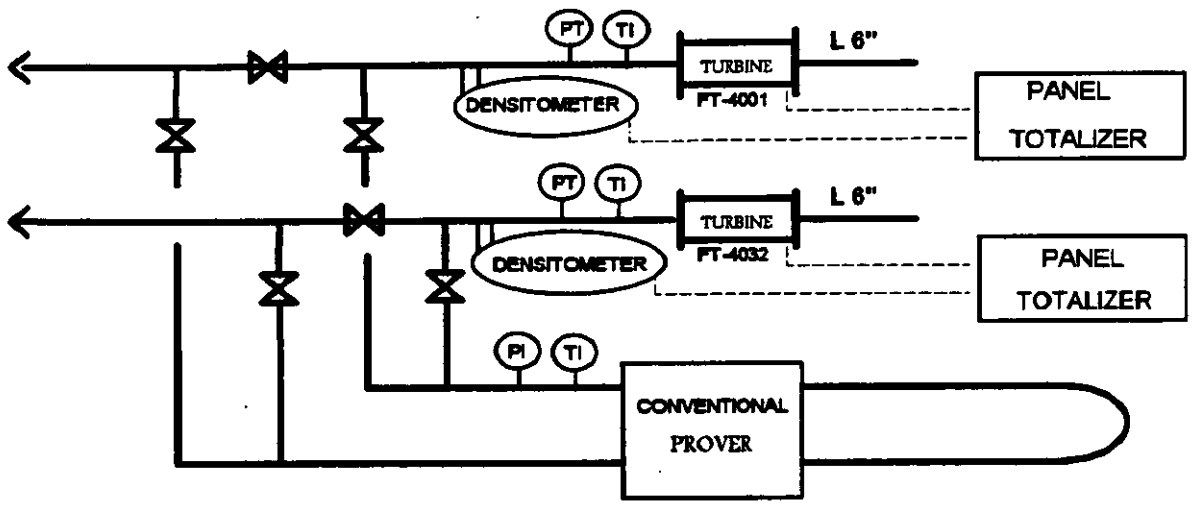
Among the equipment of the EMEDs, the flowmeters stand out as being the essential equipment and the provers as being that of the greatest hierarchical precision.

2 - OBJECTIVE

To evaluate the performance of the "Brooks Compact Prover", purchased to verify the Liquefied Petroleum Gas flowmeters of the Paulínia Refinery by the performance of comparative tests with an existing "Conventional Prover".

3 - THE PAULÍNIA REFINERY LPG MEASUREMENT STATION

Figure 1 illustrates in simplified manner, in the form of a flow chart, the interconnections of the main components: turbine-type flowmeters, densitometers, and prover of REPLAN Liquefied Petroleum Gas (LPG) Measurement Station.



GENERAL SCHEME OF LPG MEASUREMENT STATION

Figure 1

3.1 - Main meters of Paulínia Refinery Measurement Station

For quantification of the LPG to be sold, the product is pumped, passing first through a system of deaeration, filtration, and flow rectification before reaching the turbine and densitometer shown in Figure 1.

The Paulínia Refinery Measurement Station has two A. O. Smith Systems turbines[1], Model L6", with a basic "K" factor of 6000 pulses/m^3 (factory nominal K factor), represented in Figure 1 with the following designations: FT-4001 and FT-4002. The "K" factor of a turbine is the ratio between the pulses generated and the volume measured.

The densitometer used by the Paulínia Refinery in the LPG Measurement Station is of the Dynatrol brand. The density signal, after conversion of frequency to current, has the following correspondences: 20 mA is equivalent to 600 kg/m^3 and 4 mA is equivalent to 500 kg/m^3, which are the density limits of the LPG specified for sale.

Figure 2 below shows the scheme of the signals that are received from the turbine and from the densitometer by the totalizer. The Paulínia Refinery LPG Measurement Station uses a Model CMOS CDC-75 totalizer from Smith Meter[2] for each measurement line.

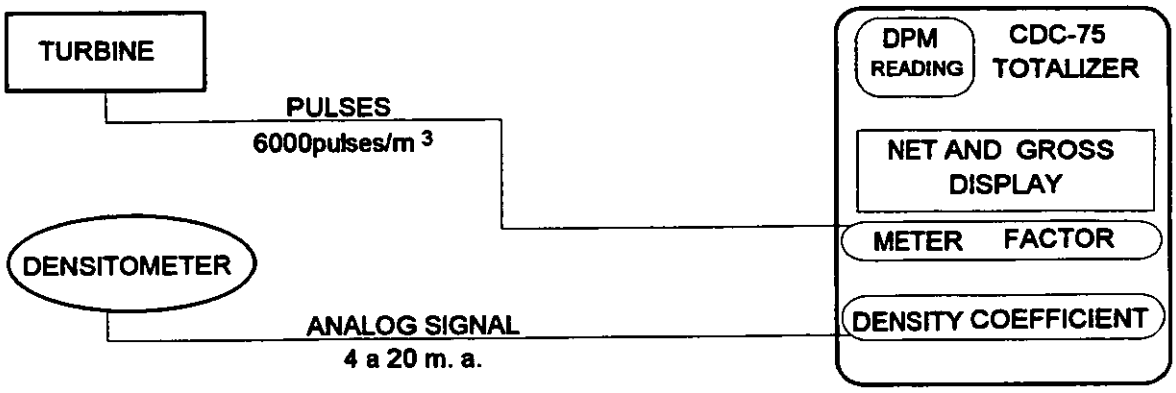


DIAGRAM OF SIGNALS TO THE TOTALIZER

Figure 2

3.2 - Totalization by weight of LPG

The CMOS CDC-75 totalizer located in the panel receives pulses corresponding to the volumetric flow rate sent by the turbine and analog current signal of 4 to 20 mA sent by densitometer. The signals are multiplied inside the totalizer to obtain the quantity transferred by weight in accordance with equations (1) to (3), shown below:

$$\text{NET MASS} = P \,.\, Mp \,.\, [\,1 - Xd\,] \tag{1}$$

$$Mp = (\,Dmax\,) \div (\,K) \tag{2}$$

$$Xd = \frac{(\,Dmáx - Dmin)}{Dmáx \times 0.9} \times \frac{DPM}{100} \tag{3}$$

The terms of equations (l), (2), and (3) have the following meanings:

NET MASS = totalized weight
Mp = meter pulse factor
Xd = DPM reading density scale
P = number of pulses coming from meter
K = meter factor: pulse/m^3
Dmax = maximum density
Dmin = minimum density
DPM = internal scale of density signal in CMOS CDC-75 with range of 0 to 90

The METER FACTOR seen in figure 2 means the Meter pulse factor (Mp) corrected by Meter Factor (MF), obtained by proving meter.

The display GROSS seen in Figure 2, indicates pulses comes from meter are totalized without the density correction [1 - Xd].

The DPM scale has the following correspondence with the analog density signal:

I = current signal
For the minimum density: Imin = 4 mA ⇒ DPM = 90
For the maximum density: Imax = 20 mA ⇒ DPM = 0

Xd has negative signal in equation (1) to do the density correction from gross to net weight, thus if operating density is equal maximum, doesn't have any correction and GROSS is equal NET weight, but if operating density is equal minimum then DPM=90 and the maximum correction is done.

The DENSITY COEFFICIENT, seen in Figure 2, must be entered into the totalizer in order to configure it according to the product to be measured. The density coefficient is obtained by the first part of equation (3) and it may be written as equation (4), below:

$$\text{density coefficient} = \frac{(\text{Dmax} - \text{Dmin})}{\text{Dmax} \times 0.9} \qquad (4)$$

To quantify by weight the LPG sold by the Paulínia Refinery, the CDC-75 totalizer comes to have the following configuration:

Maximum and minimum densities of the Paulínia Refinery LPG:

Dmax = 0.6 t/m^3 (0.6 g/cm^3)
Dmin = 0.5 t/m^3 (0.5 g/cm^3)

Applying in equation (4):

$$\text{density coefficient} = (0.6 - 0.5) \div (0.6 \times 0.9) = 0.1852$$

Applying density coefficient in equation (3):

$$Xd = 0.1852 \times \frac{DPM}{100}$$

Applying turbine "K" factor in equation (2):

$$Mp = \frac{0.6\ t/m^3}{6000\ pulse/m^3} = 10^{-4}\ t/pulse$$

At this point is important to choose the meaning of quantities that will be totalized. PETROBRÁS/REPLAN chosen to totalize each 1 dt (1 decimal ton = 100 Kg) of LPG. Then changing Mp from "ton" to "dt", the equation (2) gives Mp = 10^{-3} dt/pulse. But to set the totalizer with Mp = 10^{-3} dt/pulse is impossible, because the CDC-75 gives only possibilities between 0.0000 and 1.9999 for Mp values.

To solve this problem, CDC-75 has the possibility of multiply Mp by 10, 10^2, 10^3 or 10^4 since that the same number will be used to divide pulses coming from meter, by setting totalizer pulse divisor.

In this case Mp = 10^{-3} dt/pulse must be multiplied for 10^3 to obtain Mp = 1 dt/pulse and pulses coming from meter must be divided by 10^3 to compensate.

Configured in this manner, the equation (1) becomes:

$$M = \frac{P}{(10^3)} \times Mp \times [\,1 - Xd\,] \qquad (1)$$

$$M = \frac{P}{(10^3)} \times \frac{1\ dt}{pulse} \times [\,1 - 0.1852 \times \frac{DPM}{100}\,]$$

In accordance with the equation (1) as REPLAN configuration represented above, when 100,000 pulses are coming from the meter, with LPG density of 0.55 t/m^3 (DPM = 45), the display GROSS totalization will be:

GROSS = (100,000/10^3) dt
GROSS = 100 dt (10 ton)
Not corrected for the density.

The display NET will be corrected for density = 0.55, firstly finding Xd by equation (3):

Xd = 0.1852 x (45 / 100) = 0.08334

and forward calculating NET MASS by equation (1):

NET MASS = [(100,000 pulses) / (10^3)] x (1 dt/pulse) x (1 - 0.08334)
NET MASS = 91.67 dt (9.167 ton)
For corrected density.

3.3 - The function of the prover

Flowmeters of the turbine type, when perfectly calibrated, operate with margins of error below 0.2%, according to data from the literature and manufacturers' catalogs[1]. Because of they presenting such a high precision of measurement, as well as their ruggedness and other favorable mechanical characteristics, turbines are considered the best meters currently available on the market for industrial applications within the limits of viscosity, temperature, and other physical properties of the fluids, which, depending on the value, may hinder their use. The API MPMS Chapter 5[3] provides orientations with limits of application of turbines.

Despite the advantages presented by turbines, if a Measurement Station, contemplated with turbines, does not have a prover for verification of the same, it will be quite difficult for the user to detect whether the turbines are measuring the flow rate correctly or if they are requiring correction of the "K" factor. It will also be difficult to perceive when a turbine will be requiring maintenance due to some subtle defect that could cause errors in the measurement. The prover is the instrument that manages to achieve monitoring of the performance of the turbine.

3.4 - Method of verification of meters

The Meter Factor, according to the API, is a number which multiplied by the indicated flow rate of a turbine taking its basic "K" factor into account, furnishes the actual flow rate, eliminating the intrinsic errors of the meter during a process of custody transfer.

The Paulínia Refinery uses tubular provers called "Pipe-Provers" by the API[4,5], the main function of which is to verify the flowmeters and determine the Meter Factor. Determination of the Meter Factor is accomplished by the prover by means of a field operation called "run".

The verification "run" of a turbine consists of making an alignment in series of the latter with the prover so that the same flow rate passes through the prover and the turbine at the same time. The calibrated volume of the prover is equipped with detectors that start and stop the electronic counting of the turbine pulses, during the proving, by means of the passage of a sphere, or piston , according to the type of prover, which is launched into the flow of the product within the prover pipe.

Conventional provers[4] normally use a polyurethane sphere and compact provers[5,6] normally have a metal piston integral with an "optical ruler".

The measured turbine volume, corresponding to the pulses that prover have been counted during the passage of the sphere, or of the optical ruler of the piston, through the detectors of the prover, when compared to the prover' calibrated volume, provides the calculation of the Meter Factor. To perform the cited calculation, the volumes must be corrected to the same reference condition of pressure and temperature.

According to API MPMS 12.2[7], the Meter Factor may be defined as being the ratio between the calibrated volume of the prover and the volume measured by the flowmeter during proving run.

Equation (5) below, whether referred to the same temperature and pressure conditions, expresses API definition.

$$MF = \frac{\text{prover volume}}{\text{volume measured by meter}} \qquad (5)$$

The prover volume is calibrated by a test standardized by the API[4,5] called "water draw". The test procedure may also be found in the prover manufacturer's catalog[6].

The volume measured by turbine is taking by the ratio between number of pulses generated during the proving run and turbine's basic K factor, as showing in equation(6):

$$\text{volume measured by meter} = \frac{\text{number of pulses}}{\text{K factor}} \tag{6}$$

Adding into equation (6) the temperature and pressure corrections as contained in API MPMS 12.2[7], replacing the terms in equation (5) and rearranging them, the result is the expression of equation (7):

$$MF = \frac{(\text{prover volume}) \times (\text{K factor}) \times (CTSp) \times (CPSp) \times (CTLp) \times (CPLp)}{(\text{number of pulses}) \times (CTLm) \times (CPLm)} \tag{7}$$

The terms CTSp and CPSp of equation (7) are, respectively, correction factors of the steel volume of the prover for the actual temperature and pressure inside the prover that differ from the prover calibration conditions. The other terms of equation (7): CPLp, CTLp, CPLm, and CTLm, are, respectively, the correction factors of liquid pressure inside the prover, liquid temperature inside the prover, liquid pressure in the meter, and liquid temperature in the meter. Equations (8) to (13), extracted from API MPMS 12.2[7], provide the calculation of these terms.

$$CTSp = 1 + (Tp - Tr)\,\gamma \tag{8}$$

$$CPSp = 1 + Pp \times \frac{D}{E \times t} \tag{9}$$

$$CPLp = [\,1 - (Pp - Pe) \times F\,]^{-1} \tag{10}$$

$$CTLp = 1 - (Tp - Tr) \times \alpha \tag{11}$$

$$CPLm = [\,1 - (Pm - Pe) \times F\,]^{-1} \tag{12}$$

$$CTLm = 1 - (Tm - Tr) \times \alpha \tag{13}$$

in which:

Tp = actual temperature of liquid inside prover
Tr = reference temperature at which prover was calibrated
γ = coefficient of volumetric expansion of prover calibrated pipe material
D = Internal diameter of prover calibrated pipe section
Pp = actual internal pressure in prover
E = Modules of Elasticity of prover calibrated pipe material
t = wall thickness of prover calibrated pipe section
Pe = vapor pressure at actual, or at a conservative given, temperature.
Reid Vapor Pressure may be used as the value of Pe.
F = compressibility factor of the liquid. Value found in API Tables chapter 11[8]
α = coefficient of volumetric expansion of liquid
Pm = actual liquid pressure inside meter at run timing
Tm = actual liquid temperature inside meter at run timing

The value of Meter Factor (MF) obtained by the above methods and equations, must be multiplied with the value of totalizer configured Meter pulses factor (Mp) and the result must be entered manually in the totalizer METER FACTOR place as seen in Figure 2 of Section 3.1. During the totalizer counting pulses operation, the entered value of MF will be multiplied by number of pulses coming from the meter, to get the correct volume as shown by equation (14) below, extracted from API MPMS 12.2[7].

$$(\text{ACTUAL VOLUME}) = (\text{INDICATED VOLUME}) \times (\text{MF}) \qquad (14)$$

In this manner, after a verification run on a Paulínia Refinery Measurement Station turbine, if an MF value of MF = 0.9955 is obtained by the prover and this number is entered in the totalizer, following the same example for the calculation of Mp shown in section 3.2, for every 100,000 pulses of the turbine with LPG density equal to 0.55 t/m3 (DPM=45), the display GROSS totalization now will be:

GROSS = ($100{,}000/10^3$) dt x (0.9955) = 99.55 dt
(9.955 ton instead of 10 ton in the example of section 3.2)

The NET MASS in this case will be corrected by actual density in the same way as seen in example of section 3.2 with equations (1) and (3):

From equation (3): Xd = 0.1852 x (45 / 100) = 0.08334

From equation (1): NET MASS = GROSS x (1 - 0.08334) = 91.25 dt
(9.125 ton instead 9.167 ton in example of section 3.2)

Another way to interpret the meaning of the Meter Factor (MF) is to consider as the ration between the basic "K" factor of the meter and the actual "Net K" factor obtained by the proving. Equation (15) exemplifies this meaning.

$$\text{MF} = \frac{\text{nominal K factor}}{\text{Net K factor}} \qquad (15)$$

It should be noted that equations (15) and (7) have exactly the same meaning and calculation of the Meter Factor made by either of them leads to the same value of MF.

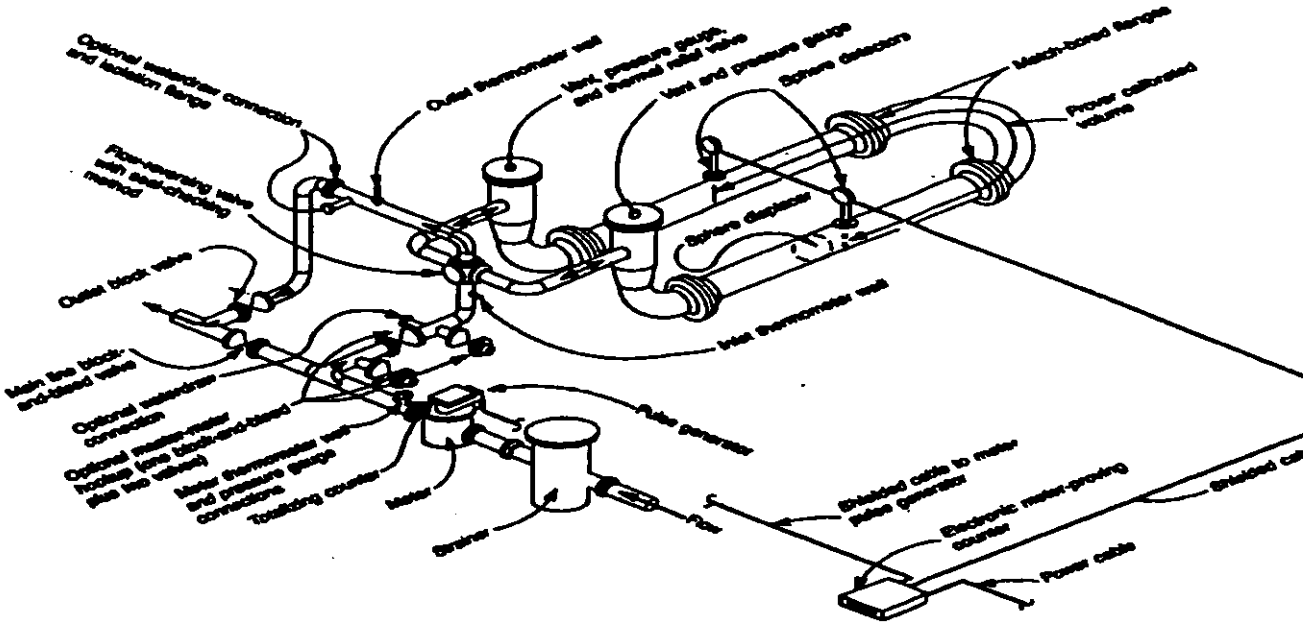
4 - CONVENTIONAL AND COMPACT PROVERS

All tubular provers for in-line connection, the calibrated volume of which permits counting of at least 10,000 pulses originating from the meter to be verified, are called "conventional provers" by the API[4]. The reason for the 10,000 pulses is so that the counting pulses error to obtain the Meter Factor must be at least ± 0.02% or better, in accordance with API.

A proving run with at least 10,000 integer pulses counted, if the first or the last one haven't been correctly detected, the error will be around: (± 2) ÷ (10,000) = 0.02%.

Such provers are called conventional because of they had been the first in-line provers for piping systems to be standardized by the American institute .

Figure 3 extracted from API MPMS Chapter 4[4], provides an illustrative drawing of a conventional and bi-directional prover.



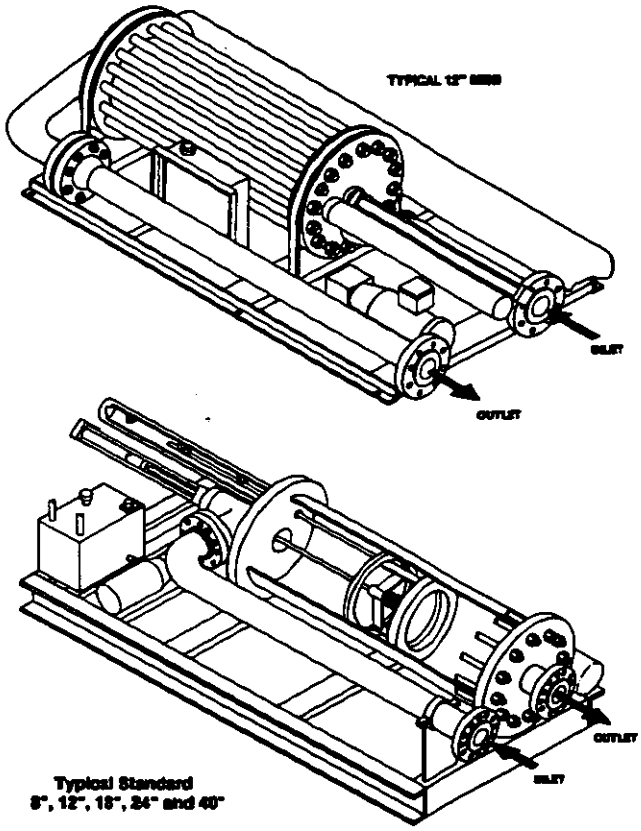
CONVENTIONAL PROVER

Figure 3

The provers called "compact" by the API[5] are those for which the calibrated volume does not permit the 10,000 pulses to be accumulated. In this type of prover, the calibrated volume is about ten times less than in the conventional. The precision of the verification and the error margin are assured by a process of counting and interpolation of pulses, called double chronometry, that is standardized by the API MPMS[6,9].

With the interpolation of pulses, the equation (7) of Section 3.4 ends up with the term "number of pulses" in the denominator, interpolated to approximately three places after the decimal point, whereas for conventional provers, in which whole pulses are counted directly, this term is an integer number.

Figure 7 shows Brooks compact prover similar to the one purchased by Paulínia Refinery.



BROOKS COMPACT PROVER

Figure 4

5 - PURCHASE AND INSTALLATION OF THE NEW PROVER

Besides the LPG Measurement Station, the Paulínia Refinery (REPLAN) has two more measurement stations, one for kerosene, gasoline, diesel and petrochemical naphtha, and another for fuel oil. For each group of these products, the exist a dedicated prover. These tree provers that have handled the REPLAN Measurement Stations for twenty years have the following tags:

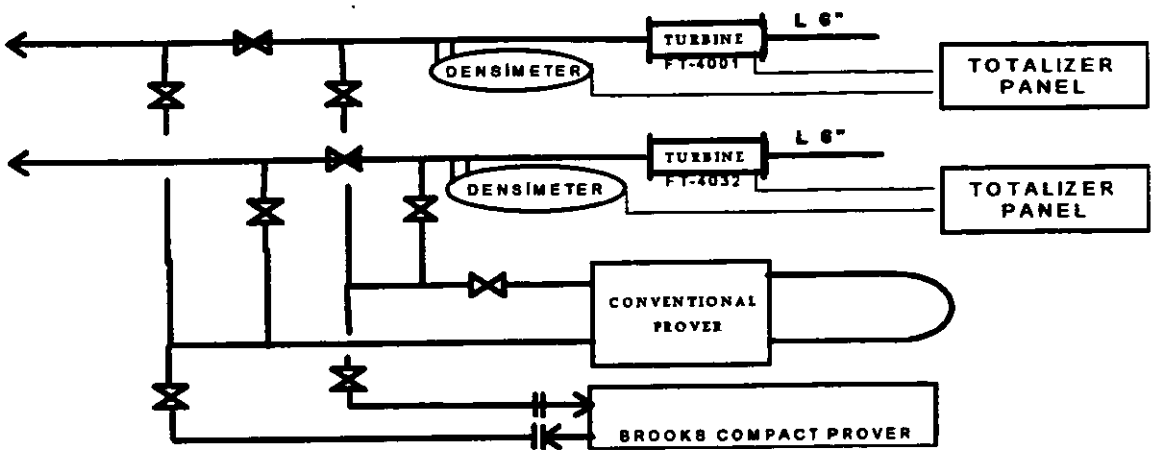
Prover 1 - handles the clear products (execpted LPG).
Prover 2 - handles the fuel oil.
Prover 3 - handles the LPG.
All these are of the conventional type.

In the end of 1993, the refinery purchased a new prover with the purpose of replacing the Prover 3 in its Liquid Petroleum Gas Measurement Station.

The reasons for the replacement were the constant problems presented in the hydraulic system of Prover 3, with consequent low operating availability and the aggravation of its being an old prover, already out of production. The new prover received the tag of Prover 4.

For the purchase of the new prover, a public bidding was held, in which tree companies with technical acceptance proposals participated. The successful bidder, by the criterion of lowest price, was the American company, Brooks, represented in Brazil by Hirsa, with the proposal of a compact prover.

Figure 5 shows the interconnection of the new prover in the LPG Measurement Station:



INTERCONNECTIONS WITH THE NEW PROVER

Figure 5

The prover furnished by Brooks is a model with volume of 120 liters, diameter of 18 inches, and operating range of 8 to 800 m^3/h. This was the fourth compact prover to be purchased in Brazil.

Among the first three ones, only COPENE's prover had a good operation run. The other two (one bought by PETROBRÁS and another bought by a multinational oil company), hadn't had good operation results. They had many different problems, they didn't obtain the prescribed repeatability, they obtained many different Meter Factors for the same flowmeter without a good reason, and other kind of problems. Error in the system's assembly or in the process conditions may be the sources of these problem.

Although COPENE have had good operation performance, they never publish any report from which Brazilians engineers can take good lecture reference in that country conditions. For Brazilians, compact prover for chemical and oil companies, was a failure experience, they almost guilt the compact prover technology, before REPLAN's tests.

6 - COMPARATIVE TESTS

In September 1994 a no-load startup was made on REPLAN's Prover 4 and the first experimental runs were made. At that time, some problems originating from the power supply installation were detected and corrected. Once the installation problems were corrected, the prover operated normally when the evaluation testing began in earnest.

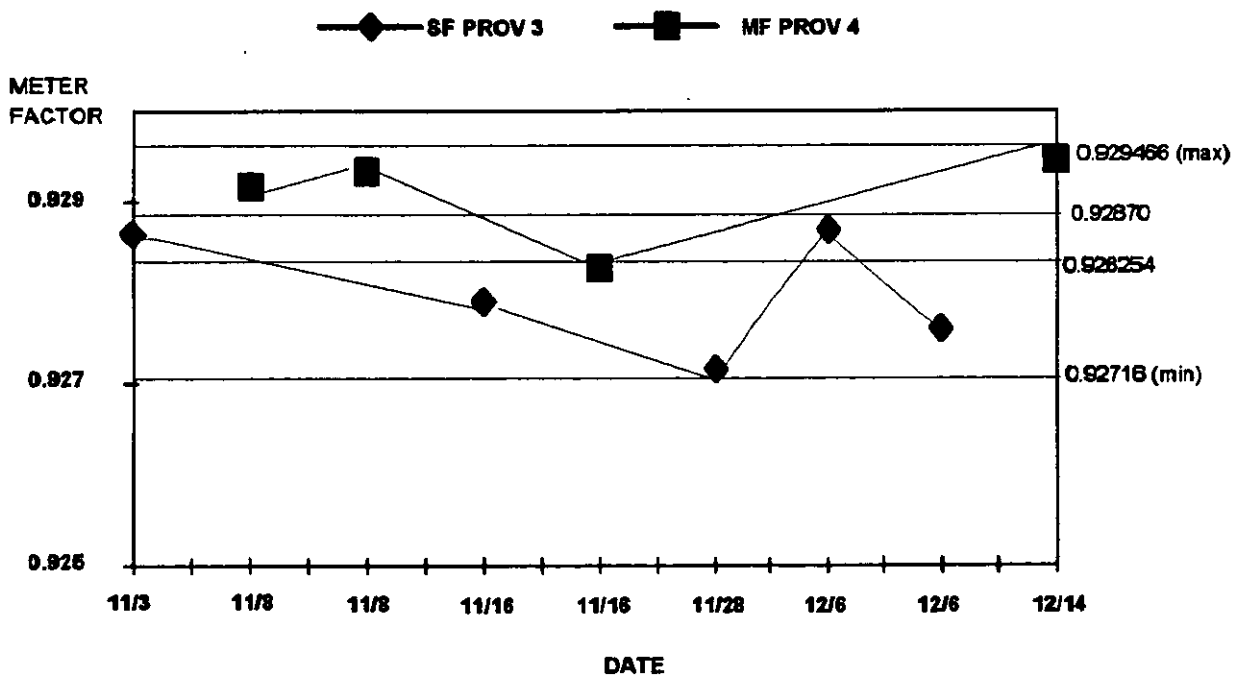
To verify the performance of Prover 4 in the field, operating during a process of transfer of custody transfer, the LPG turbine FT-4001, shown in Measurements Stations Figures 1 and 5, was selected as reference for comparisons to be made between the Meter Factors obtained for this turbine with Prover 3 (conventional), called FS in Brazil, and the Meter Factor obtained with Prover 4 (compact) called MF, to distinguish them in the graphs and tables below, containing the presentation of the comparative results.

The tests were performed taking care to verify and use, for the calculations of FS and MF, the same temperature and pressure references of calibration of the provers and the correction factors: CPLp, CTLp, CPSp, CTSp, CTLm, and CPLm from API MPMS 12.2[7]. Also observed for all runs was repeatability better than 0.05% like API recommends[5,10].

The first comparative sampling of the results of verification runs was obtained during the period between November 8, 1994 and December 15, 1994, in which four verifications of the FT-4001 Meter Factor, with the compact prover were made, and several runs with the conventional prover.

Among the verifications made with Prover 3 (conventional), the four that took place on dates closest to the runs made with the compact prover were taken so that the factors obtained between the two provers could be compared for the same turbine.

The results have been plotted on the graph in Figure 6.



COMPARISON OF FACTORS OBTAINED: PROVER 3 VS. PROVER 4

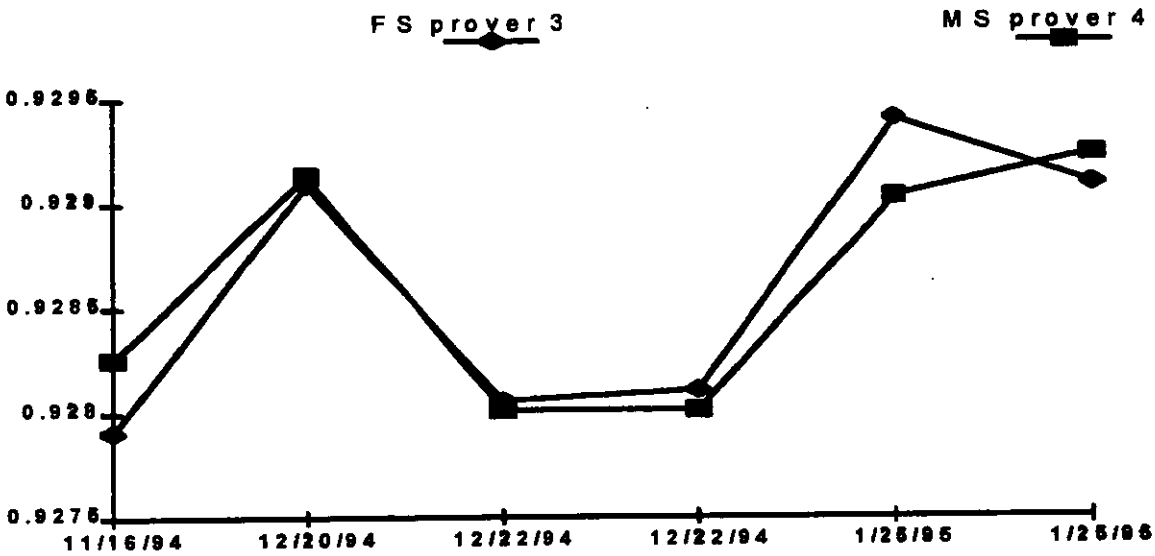
Figure 6

The sampled data are found in Table I.

Table I

DATE	FS PROVER 3	MF PROVER 4	flow rate m^3/h	temp. ^oC	pressure KPa
11/03/94	0.928645		154	30	0950
11/08/94		0.929153	233	29	1250
11/08/94		0.929342	253	30	1200
11/16/94	0.92791		345	31	1550
11/16/94		0.928254	272	34	1350
11/28/94	0.92716		254	24	1150
12/06/94	0.92870		309	32	1550
12/06/94	0.92760		318	31	1550
12/14/94		0.929466	270	37	1300

It is normal that Meter Factors present such variations through changes in the pumping conditions of the same product: flow rate, pressure, and temperature. Taking this fact into account, a second phase of testing was carried out, seeking to compare the factors obtained by the two provers with runs made for the same pumping. The results have been plotted on the graph in Figure 7.



COMPARISON MADE FOR THE SAME PUMPING CONDITIONS

Figure 7

The data from the runs represented in the graph of Figure 7 may be better visualized in Table II:

TABLE II

DATE	FS prover 3	MF prover 4	differences
11/16/94	0.92791	0.928254	-0.000344
12/20/94	0.929093	0.929135	-0.000042
12/22/94	0.92806	0.928014	0.000146
12/22/94	0.92811	0.928013	0.000097
01/25/95	0.929406	0.929033	0.000373
01/25/95	0.929095	0.929237	-0.000142

7 - ANALYSIS OF RESULTS

7.1 - Comments of first phase tests results

Analyzing the first phase of testing, the results of which are in Table I, taking as reference the minimum value of the factors obtained for each prover:

The variations in MF by Prover 4 were:
(0.929466 - 0.928254) / (0.928254) = 0.131%

The variations in FS by Prover 3 were:
(0.92870 - 0.92716) / (0.92716) = 0.166%

The average of the factors obtained by Prover 4:
MFaverage = 0.92905375

The average of the factors obtained by Prover 3:
FS average = 0.928003

Difference in averages of the two provers:
0.00105075 or 0.113227%

According to API MPMS 12.2[7], a good criterion for monitoring and control of the Meter Factor by means of a "flow chart" is to permit a maximum tolerance in variation on the order of 0.25%.

From the data of Table I and the graph of Figure 6, it is noted that this criterion has been met by both provers.

7.2 - Comments of the second phase of tests results

From the analysis of the second phase of testing, when the comparisons were made under similar pumping conditions and the results of which are found in Table II and in the graph of Figure 7, the following comments may be made:

In Table II, it is observed that the major difference between the factors obtained by the two provers in the same pumping took place in a run made on January 25, 1995, showed a variation between FS and MF of 0.0373%. This order of variation is possible of occurring even with the same prover, as may be observed with Prover 3, when the difference for the two runs on the 25th day (same pumping) was 0.0311%.

It is also noted that for the runs of the same pumping, the differences observed between the two provers are less than 0.05%. According to API MPMS 4.2 Appendix B[5], this is the range of repeatability that a conventional prover must achieve with the launchings of the sphere for pulse counting, or a compact prover with groups of piston launchings, for a proving run. The data show that the variation in factors obtained by the two provers, in the refinery facilities during the testing period, was within the range of variation allowed by the API[5] for a single prover, indicating that the performance of both was practically equal. The difference in averages was consider to be zero.

7.3 - Comments of the comparative results between the two phases tests

Comparative analysis of the two testing phases permits the following comments:

The results of the graph in Figure 7, when compared with those of Figure 6, show a greater approximation between the values obtained by the two provers. It confirms that the Meter Factor is affected significantly by variations in the pumping conditions like the flow rate, the temperature and pressure.

In the period covered by the graph in Figure 7, Prover 3 exhibited a variation of 0.161% while Prover 4 exhibited 0.132%. These figures are quite close to those observed in the period covered by the graph in Figure 6, when Prover 3 exhibited a variation of 0.166% and Prover 4 exhibited 0.131%. Its confirmed in these tests analysis that the compact prover exhibited variations less than the conventional, on the order of 0.13% versus 0.16% in the monitoring of the factor of FT-4001.

According to the catalog of the manufacturer of the turbine, variations of tip to 0.20% in its factor are normal. These above figures indicate that turbine FT-4001 is in perfect condition and that the factors obtained by both provers had a normal variation; below the 0.20% advised by the manufacturer.

8 - CONCLUSIONS

To perform the tests with both provers during the same pumping condition was a difficult task due to the maneuvers and operations required to make the alignments correctly and safely. Such procedures caused the time expended on the testing to be extensive, besides requiring the collaboration of the operators, who also had to be attentive to the other occurrences of the various systems that are operated from the same measurement station panel. Although collected data may appear to be few, they results presented here were considered sufficient to reach the following conclusions:

The factors obtained by both provers are in conformity with the API recommendations indicating that the Paulínia Refinery LPG Measurement Station is in good operating condition.

The performance of the compact prover during the testing carried out was quite good, having slightly surpassed the conventional prover in terms of repeatability and of less spread in the calculated factor: 0.13% vs. 0.16%.

The acquisition of pressure and temperature data directly from transmitter available in the new prover avoids probable readout errors and loss of time with the manual collection of information made for the old provers.

Calculation of the meter factor, with the compact prover, is done by the same computer that operates the equipment, whereas in the conventional prover it is done with calculators or on a PC computer with data entry in the form of keyboard entry, thus being more subject to errors and more delayed.

The new prover, besides being more rugged, supporting several simultaneous runs without problems, is faster, consuming for performing a run about 1/10 of the time spent by the conventional.

Despite its being a new equipment for operators, with more electronic components, there was no difficulty in assimilation by the operators and maintenance people in the training of the compact prover.

From the results of the testing, Prover 4 was considered suitable for entering into the normal operating regime, being available and reliable for correcting the factors of the Measurement Station turbines.

The Paulínia Refinery compact prover tests, was published in Brazil's meetings and technical magazines. After these PETROBRÁS/REPLAN tests, more than 10 compact provers have being purchased in the last two years. These evaluating tests, introduced the compact prover and double chronometry technologies in Brazil.

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[7] American Petroleum Institute - Manual of Petroleum Measurement Standards, Chapter 12, "Calculation of Petroleum Quantities", Section 2, "Calculation of Liquid Petroleum Quantities Measured by Turbine or Displacement Meters".

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Main Index

North Sea FLOW Measurement Workshop 1995

Paper 3:

IN-SITU CALIBRATION OF 500 MM DIAMETER ORIFICE METERS

1.3

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IN-SITU CALIBRATION OF 500 MM DIAMETER ORIFICE METERS

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Summary

Research conducted by Chevron in 1983 indicated that large diameter orifice meters may be subject to unforeseen installation effects. In order to determine if there were installation effects on three 500 mm diameter custody transfer orifice meters, a sonic nozzle in-situ proving system was installed to prove the meters. The custody transfer orifice meters are located at the outlet of the NOVA Gas Transmission Ltd. Kaybob South No. 3 meter station in northern Alberta, Canada. The in-situ proving facility was designed and conducted by NOVA at the request of Chevron Canada Resources. Chevron Petroleum Technology Company (CPTC) assisted with both the design and operation of the proving facility.

The three 500 mm diameter orifice meters each have a maximum capacity of 10,000 E3M3/D and were installed in 1989 according to specifications that exceed the current American Petroleum Institute (API) orifice metering standard. The sonic nozzle proving system was designed and installed in accordance with the American National Standards Institute (ANSI) MFC 7M. The nozzle system consisted of eight parallel 150 mm diameter nozzle runs and a 300 mm bypass turbine meter. Combinations of nozzles with diameters of 18 mm, 26 mm, 31 mm, and 38 mm are used to achieve flow rates throughout the range of the orifice meters. The nozzles were calibrated at Colorado Engineering Experiment Station Inc. (CEESI) using air. Samples from each size were tested at NOVA Gas Dynamics Test Facility (GDTF) using pipeline quality natural gas. The agreement between these two labs was within the stated uncertainties of the facilities.

Data acquisition and system control was accomplished by using high quality transducers connected to data loggers and a computerized data archiving and control system. Instrumentation was calibrated at the beginning of each day of operation and calculations were performed using a sonic nozzle mass flow program developed by NOVA for the in-situ meter prover project. The program, based on a PV=ZRT equation of state, uses the 1992 AGA-8 method for calculating compressibility factors and was verified against other independently developed programs using the 1985 AGA-8 and 1992 AGA-8 methods.

Results of the orifice meter calibrations indicated good agreement between the standard flow calculation and the proving system with low beta ratio plates. However, larger deviations occur as the beta ratio approaches 0.6. The cause of the high beta ratio deviation is under investigation. The current hypothesis, which will be tested as part of the on-going work at the facility, is that the bias is due to installation effects.

INTRODUCTION

Background

In-situ proving of orifice meters is a technology that is allowed for in current metering standards [1] but is one that is seldom practiced in field operations. The current state of the art in natural gas metering makes it possible to develop high quality and field rugged proving systems that can be used on any natural gas meter.

Chevron In-Situ Proving Prior Experience

Chevron Petroleum Technology Company (CPTC) began testing proving technology in natural gas operations in a number of locations and conditions beginning in 1981 [2, 3]. Orifice, turbines, vortex, pitotstatic, and other meters have all been installed in operating natural gas pipeline systems and proven using various sonic nozzle provers. Chevron's first commercial application of in-situ proving technology was at the Venice, Louisiana, sales meter station [4]. The Venice facility is still in operation and is currently using sonic nozzles to in-situ prove high pressure, high flow rate turbine meters. This turbine meter prover was installed in series with the existing orifice meter sales station and has performed very well in the hands of the field operating personnel since 1987.

Based on Chevron's field experience with orifice meters installation effect and its knowledge of the ease of accomplishing in-situ proving, the NOVA Kaybob South No. 3 metering station was considered, following its commissioning in 1990, by Chevron to be an obvious candidate for application of this technology.

NOVA's Metering Research

NOVA research has also been very active in evaluating the expected field performance of orifice meters. NOVA has conducted a number of installation effect experiments on orifice meters at their Gas Dynamics Test Facility at Didsbury, Alberta. The results of NOVA's research have been presented in a number of papers [5-8] and have validated measurement practices that included using meter tube lengths longer than those required by the standards, restricting the beta ratio range from 0.20 to 0.60 and minimizing the number of 50 mm orifice meters used.

NOVA's Metering Experience

Metering on NOVA's natural gas transportation system is primarily accomplished with orifice meters. There are approximately 1200 orifice meter runs in service in over 950 meter stations. The orifice meters range in size from 50 mm to 600 mm in size. NOVA's system gathers gas from gas producers and transports it to the borders of Alberta where it is passed on to connecting pipeline systems. Because of the gathering nature of the system, there is a predominance of smaller meters used to measure receipts; a small number of large orifice meters is used to measure the deliveries. In spite of the skewed distribution of meter sizes, NOVA metering balance is extremely low (typically within a few tenths of a percent) — a fact that NOVA considers to be strong evidence that no systematic bias exists between small and large diameter orifice meters.

Pretest Uncertainty Analysis of Provers and Orifice Meters

Prior to designing and constructing an in-situ meter prover for the Kaybob South No. 3 metering station, a general engineering study was conducted by Novacorp International Consulting Inc. The study included an investigation of the various proving meter options and their associated measurement uncertainty. The types of reference meters considered for the meter prover were sonic nozzles, turbine meters, and orifice meters. Novacorp recommended sonic nozzles for the in-situ meter prover because they had the lowest estimated measurement uncertainty at 0.50% for a single sonic nozzle and 0.42% for four nozzles operated in parallel (assuming a sonic nozzle coefficient of discharge uncertainty of 0.25%). Turbine meters and orifice meters, by comparison, were estimated to have an uncertainty of 0.66% and 0.76% respectively. The robust nature of sonic nozzles was also considered to be a benefit for an in-situ meter prover.

The cost to install a sonic nozzle prover was determined to be comparable to that of a turbine or orifice meter prover. Further, the required additional compression necessary for sonic nozzle operation was available at Chevron's Kaybob plant. Based on NOVA Corp's study, Chevron's partners in the Kaybob Gas Plant agreed to fund the design and construction of the NOVA Kaybob South No. 3 in-situ meter prover.

LOCATION, SPECIFICATIONS, AND OPERATING CONDITIONS

Operating Conditions

Table 1, "High Pressure Prover Loop Operating Conditions", presents the general operating conditions and specifications for the proving system. The NOVA Kaybob South No. 3 meter station is located about 200 km northwest of Edmonton, Alberta, Canada (see Figure 9). Variable climate conditions made it a requirement to locate all metering equipment inside buildings. The design gas temperature of 35°C and pressure of 8450 kPa, shown in Table 1, were not obtained in actual operation. Actual operating pressure is closer to 5000 kPa and temperature is closer to 20°C.

TABLE 1
High Pressure Prover
Loop Operating Conditions

Elevation- Kaybob South No 3	1,065 m
Barometric Pressure - Kaybob South No. 3	89.22 kPa abs.
MAOP	8,450 kPa
Design Pressure	8450 kPa
Hydrotest pressure	
Maximum	12,500 kPa
Minimum	11,800 kPa
ANSI rating for equipment flanges and valves	600 ANSI
Natural gas temperature	35°C
Base measure/computation conditions	
Pressure	101.325 kPa
Temperature	15°C
Gas composition (typical)	
Nitrogen	1.62 (MOL %)
CO_2	0.01 (MOL %)
C_1	96.0 (MOL %)
C_2	2.21 (MOL %)
C_3	0.16 (MOL %)
Gas specific gravity	0.57
Minimum flow rate	13.61 kg/s
Maximum flow rate	90.28 kg/s

Specifications

Table 2, "Sonic Nozzle Specifications", presents the design parameters for the sonic nozzles installed in the prover. All nozzles and nozzle runs were manufactured and installed according to American Society of Mechanical Engineers (ASME) ASME 7M [9]. Nozzle discharge coefficients were determined experimentally as described later in this paper.

TABLE 2
Sonic Nozzle Specifications

Nozzle Serial No.	Throat Diameter [mm]	Operating Mass Flow Rate[1] [kg/s]
5031, 5032, 5033, 5034	18	2.35
5035, 5036	26	4.90
5037, 5038, 5039, 50310, 50311	31	6.96
50312, 50313, 50314	38	10.46

Table 3, "Orifice Meter Mechanical Specifications", presents the design guidelines for the NOVA metering station. NOVA's specification exceeds the current recommendations for

[1] Based on typical operating conditions of 5000 kPa, 20 °C and 0.58 specific gravity natural gas.

upstream lengths in API 2530 [1]. In addition to extra upstream lengths, NOVA restricts the orifice beta ratio to the range from 0.20 to 0.60.

TABLE 3
Orifice Meter Mechanical Specifications

Maximum beta ratio	0.6
Distance to vane	10 D
Distance to Flange	24 D
Run 1	
Inside diameter	481.9 mm
Run 2	
Inside diameter	482.2 mm
Run 3	
Inside diameter	482.0 mm

Figure 1 presents a simplified flow schematic of the proving system. The general layout and operation of this type of proving system has been previously presented [2, 4]. However, a few important points about the design are worth noting: 1) in order to eliminate any chance of interference, the sonic nozzle bank is located downstream of the orifice meters, 2) a turbine meter bypass system was installed to account for the gas flow not being used by the prover, and 3) all important flow block valves are double block and bleed and the sealing of these valves was checked during operation.

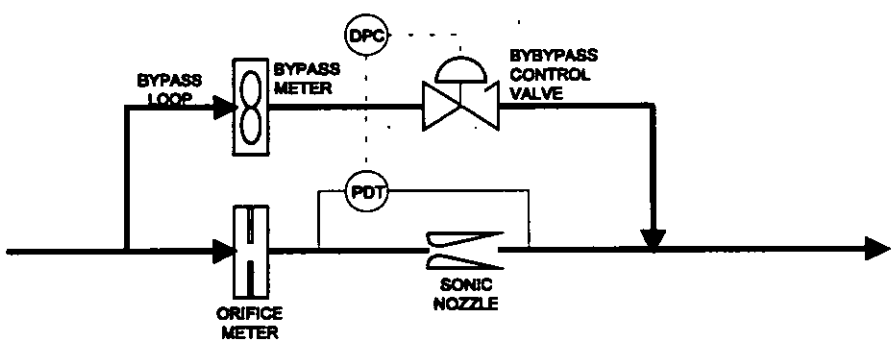

Figure 1: Simplified Flow Schematic

DATA COLLECTION AND ANALYSIS

Data collection and system control, Figure 2, was accomplished with high quality electronic transducers, modern computer equipment, and controllers. In order to ensure facility stability, and to obtain data with a low standard deviation of the sample mean, a long run time of 20 minutes or more was performed for each test point.

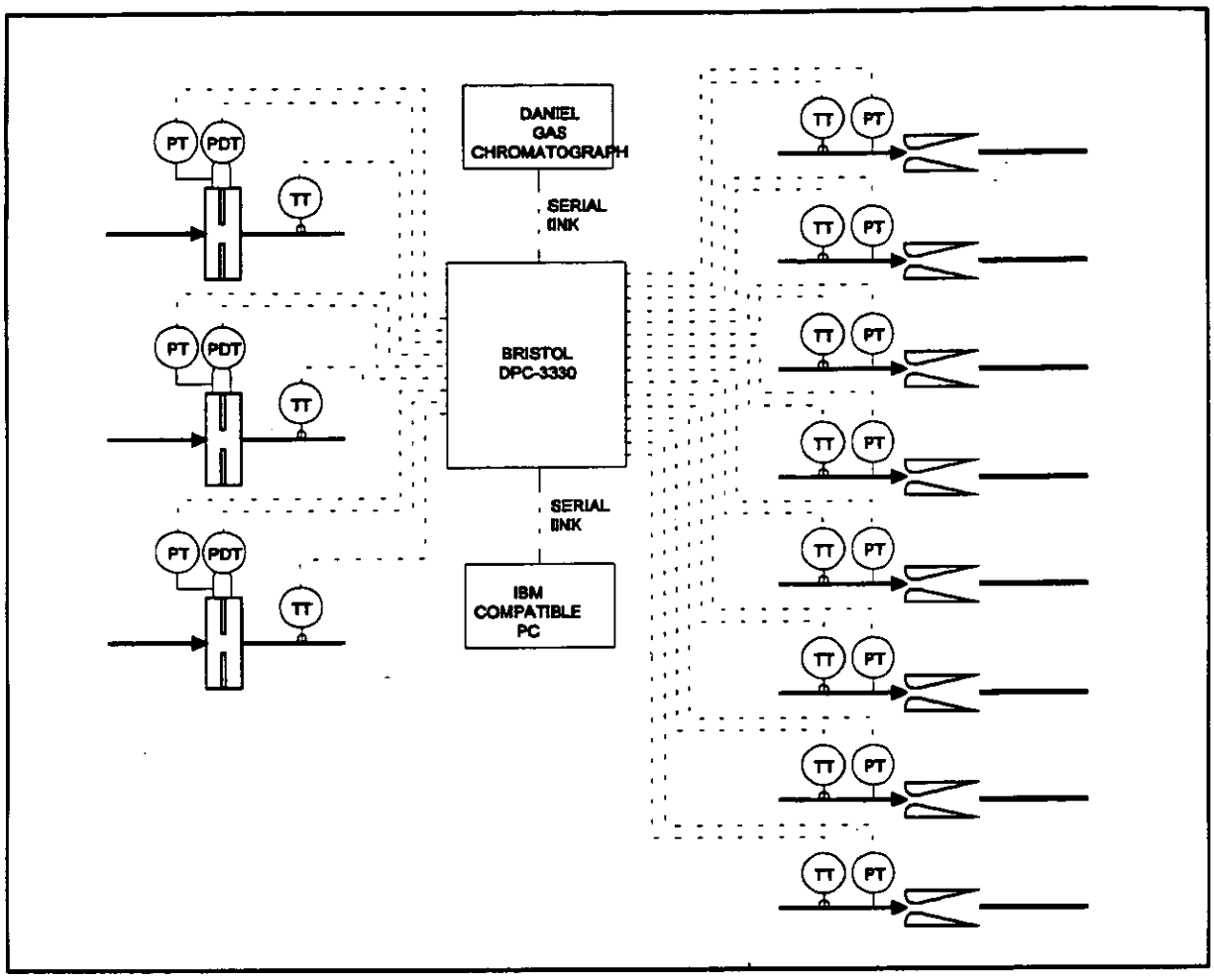

Figure 2: Data Acquisition System Schematic

During the 20 minute test period, data was collected at 10 second intervals producing 120 points. Data for each of these tests was processed by applying the transducer calibrations that were performed at the beginning of each day. The adjusted transducer readings were then combined with the gas analysis obtained from the on line gas chromatograph and a flow computed for each point.

SONIC NOZZLE OPERATION

Thermodynamics of Sonic Nozzle Operation

The calculation of flow rate through sonic nozzles requires that one know the speed of sound and the density of the gas at the throat of the nozzle. Measuring the plenum pressure and temperature, and computing throat conditions along an isentropic path is the accepted method of determining this velocity and density. Several older methods [10, 11] are publicly available to accomplish this calculation. However, as part of the project, the accuracy and traceability of the proving system was insured by NOVA developing a program to compute the sonic nozzle mass flow based on the latest natural gas equation

of state. The program is based on a PV=ZRT equation of state and uses the 1992 AGA-8 [12] method to calculate compressibility factors.

Critical flow coefficients, or C*, also calculated by this program were compared to programs based on the 1985 AGA-8 [11], and to the beta versions of the Gas Research Institute's (GRI) critical flow program which uses the 1992 AGA-8 [12]. The comparison indicated that all methods based on AGA-8 agreed to within 0.1% at typical operating conditions (plenum pressure, temperature, and gas composition). Additionally, the NOVA program agreed with the GRI critical flow program beta version to within a few hundredths of a percent.

Calibration of the Sonic Nozzles

Discharge coefficients for the sonic nozzles used in the prover were obtained by calibrating the nozzles in air at CEESI using a combined calibration method which employs both CEESI's primary and secondary facilities. CEESI's primary facility has an uncertainty of 0.1% and the secondary facility 0.5%. The uncertainty of a combined calibration was estimated by CEESI to be 0.25%.

As a quality control check, one nozzle of each size was tested in natural gas at GDTF. The estimated uncertainty of the nozzle discharge coefficients determined at the GDTF was 0.35%. Due to operating and scheduling difficulties usable data was collected for only three of the four nozzles tested at GDTF.

Table 4, "Comparison of Nozzle Discharge Coefficients", presents the discharge coefficients determined by CEESI and NOVA and compares them to the International Standards Organization (ISO) [13] standard values. As can be seen, the CEESI values vary about the standard value with a maximum deviation of 0.18%. NOVA's calibration shows a bias with respect to the standard and a maximum deviation of -0.5%. However, when the two labs are compared to each other, the agreement is within 0.31%. Considering the uncertainty statements of the GDTF and CEESI calibrations, the difference is not statistically significant.

TABLE 4
Comparison of Nozzle Discharge Coefficients

Serial Number	Cd CEESI	Percent Diff From Standard	Cd NOVA	Percent Diff From Standard	Cd Standard	Percent Diff CEESI-NOVA
5031	0.9944	0.13%	0.9918	-0.13%	0.9931	0.27%
5035	0.9914	-0.18%	0.9883	-0.49%	0.9932	0.31%
50311	0.9914	-0.18%	0.9883	-0.50%	0.9932	0.31%
50314	0.9941	0.08%	0.9900	-0.33%	0.9933	0.41%

Note: The Cd calculated from the standard are based on nominal diameters.

Choking Pressure Differential

The correct operation of a sonic nozzle requires an adequate pressure drop across the nozzle. This pressure drop, required to insure that the nozzles have sonic flow at the throat, is commonly called the back pressure ratio. Standards on critical flow venturi nozzles [9, 13] specify where the pressures are to be measured and the amount of pressure drop required, for nozzle throat Reynolds number greater than 2×10^5, as a function of the area ratio of the divergent cone of the nozzle. A common rule of thumb is that for toroidal throat nozzles, this pressure ratio, the downstream pressure divided by the upstream pressure, should be 0.9 or a 10% pressure drop.

Previous experiments carried out by Jones [14] have shown that the pressure drop required for sonic flow at the throat of the nozzle design used in this in-situ proving could be as low as approximately 5%. Reduction in the pressure drop across the nozzle allows for a reduction in the required compression horsepower and lowers the potential of processing plant and field facilities problems.

Tests were conducted at the Kaybob South #3 Meter Prover to confirm that an adequate back pressure ratio was being used during the calibration runs. Sonic operation was determined by using the meter factor as the indicator. Calibration runs were made with back pressure ratios ranging from 4% to 13%. The results, contained in Figure 8, show that the meter factors stayed constant down to a back pressure ratio of 0.94 and confirmed that the typical back pressure ratio of 10% used in the calibration runs was ample to ensure that the flow through the nozzles was choked.

RESULTS

Discussion

The data collection procedures and computerized operation of the equipment provided large amounts of data on which to base in-situ proving results. As can be seen from Figure 3, the typical data set for a calibration point consisted of over 120 data points. Data sets similar to those shown on Figure 3 were averaged to obtain a single calibration point shown on Figures 4 through 7.

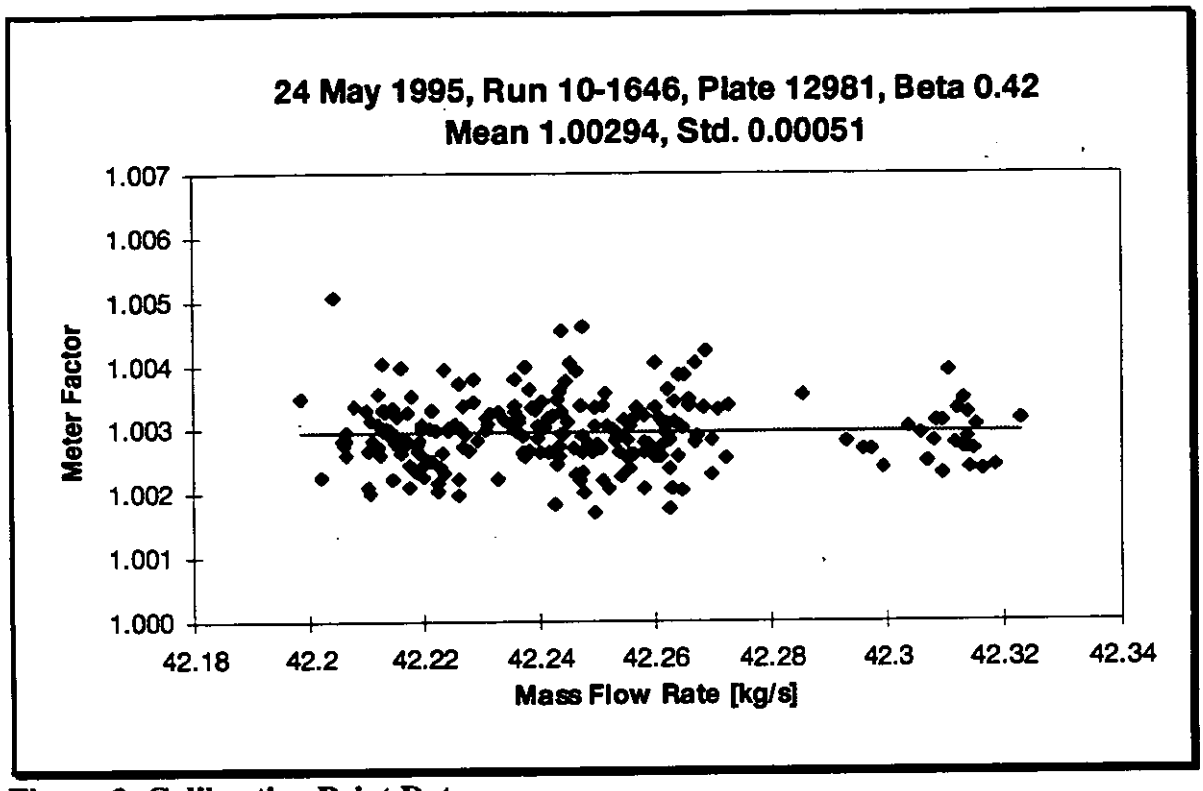

Figure 3: Calibration Point Data

The spread of the data on Figure 3 provides one with a measure of the stability of the proving and control systems. Figure 3 shows that the standard deviation of this data set is 0.051%. Visually, one can identify a few possible outlier data points; however, no attempt was made to remove these points or any others unless an operational problem could be identified that could account for the deviation.

Figure 4 shows the 0.42 beta ratio calibration points obtained for all three 500 mm runs. The data was obtained over numerous days and should contain a representative amount of scatter due to short and mid-term repeatability effects. Of note is the apparent trend in the data and the spread between the meter factors for the various meter runs and plate combinations.

The apparent trend of the meter factor with respect to the orifice bore Reynolds number could be a result of any of the following:

1. The static pressure effect on the orifice meter differential pressure transmitters.
2. An increasing bias in Cd with increasing nozzle size.
3. Gas leaking past the flow block valves on the closed orifice meter runs.
4. A bias in the orifice meter discharge coefficients predicted by the 1985 AGA-3.

The first two reasons are considered to be the most likely and will be the subject of future testing.

The spread between the various meter runs and plate combinations is the result of the specific characteristics of the individual meter runs and orifice plates. Testing was performed in an attempt to determine how much of the spread can be attributed to differences in the meter runs and how much is a result of differences in the orifice plates.

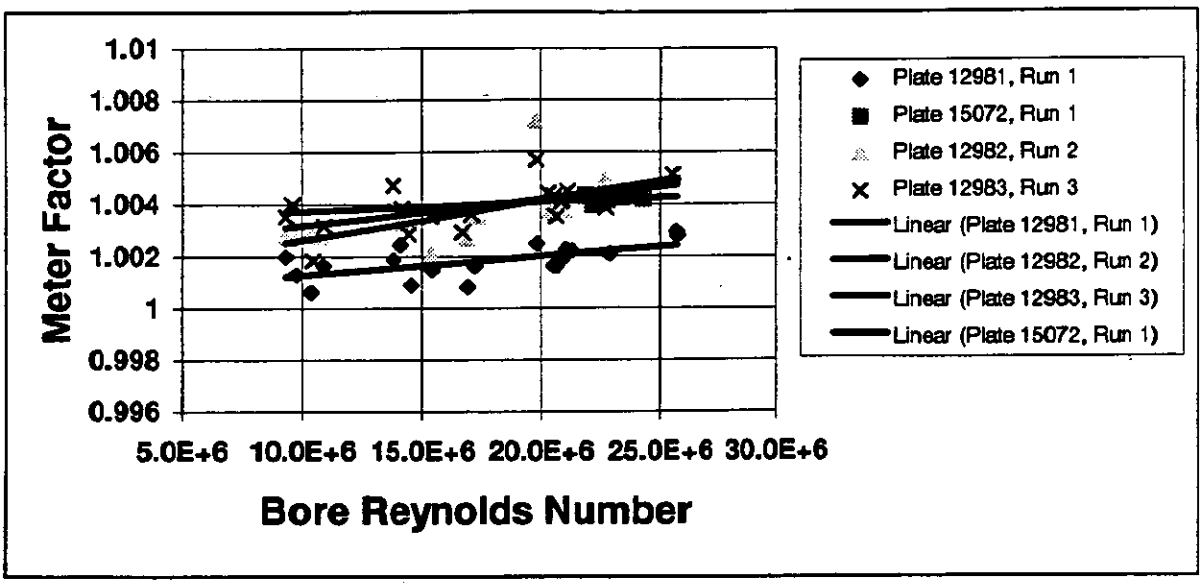

Figure 4: Beta Ratio 0.42 Calibration Points

Figure 5 shows all the 0.42 beta ratio calibration points obtained to date. The trends in the data indicate that about 0.1% of the spread in the meter factors, for the various meter run and orifice plate combinations, can be attributed to differences between the meter runs and about 0.2% can be attributed to differences in the orifice plates. Plate #12,981 has a noticeably different meter factor than the other 200 mm plates. Careful measurement of the 200 mm plates have ruled out variations in the bore diameter and eccentricity as possible causes of this difference. Future measurement and testing will hopefully reveal the cause of these observed variations.

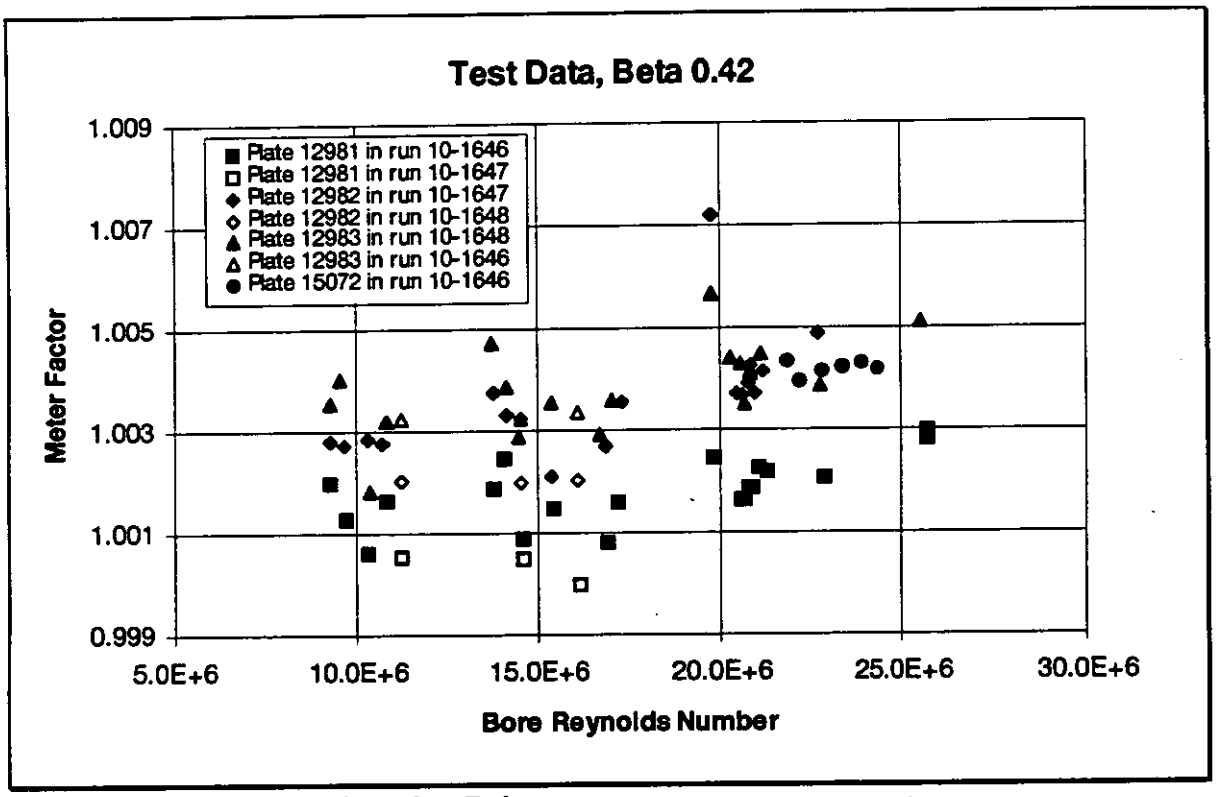

Figure 5: Beta 0.42 Calibration Points

Figure 6 is a summary of the calibration points obtained on 20 June 1995. This test was conducted specifically to measure beta ratio effect. In order to accomplish this, nozzle variation was removed by using the same nozzle configuration for the entire test. The number of orifice meter runs in parallel was varied to match the flow through the fixed nozzle bank: 3 runs with 0.32 beta ratio plates (150 mm); 2 runs with 0.42 beta ratio plates (200 mm); and, 1 run with 0.58 beta ratio plates (280 mm). This averaging procedure was justified by prior testing that has shown that a meter factor obtained from multiple flow runs operating in parallel with the same beta ratios was equivalent to the average of the meter factors for the individual runs.

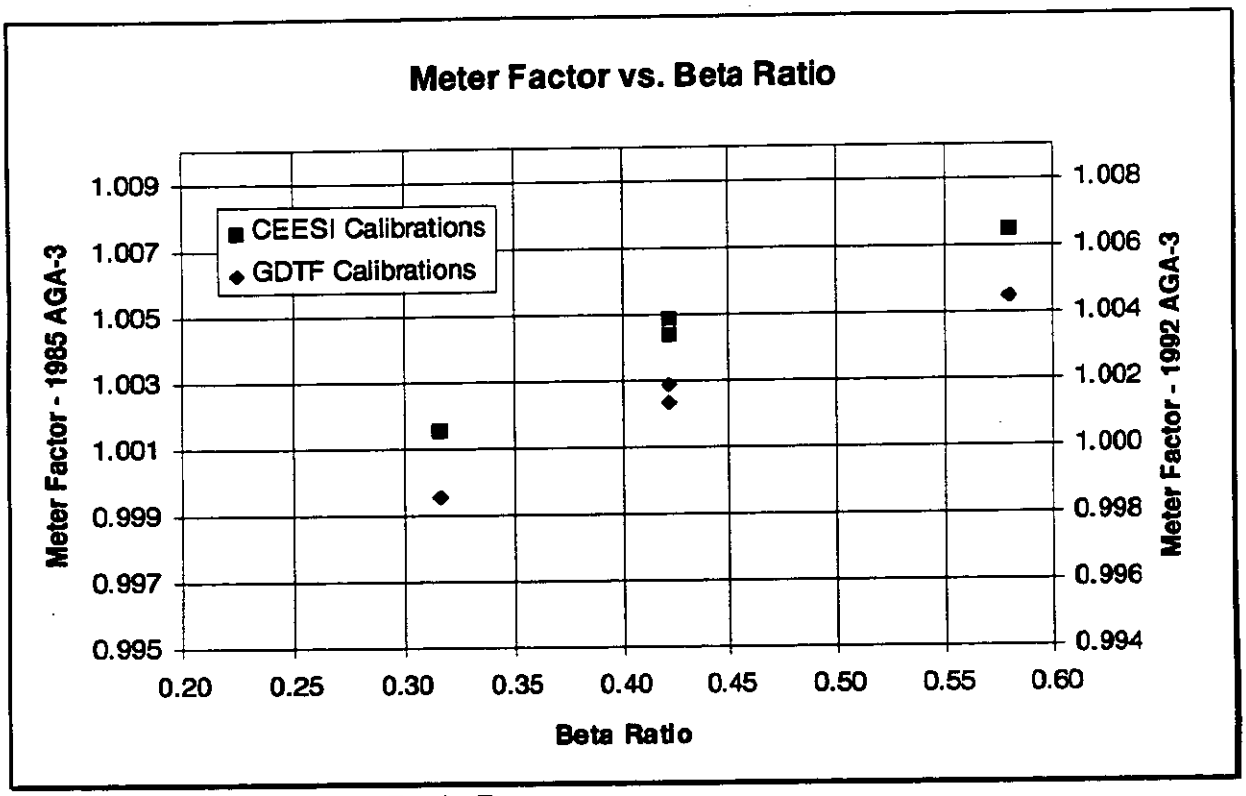

Figure 6: Results of Beta Ratio Test

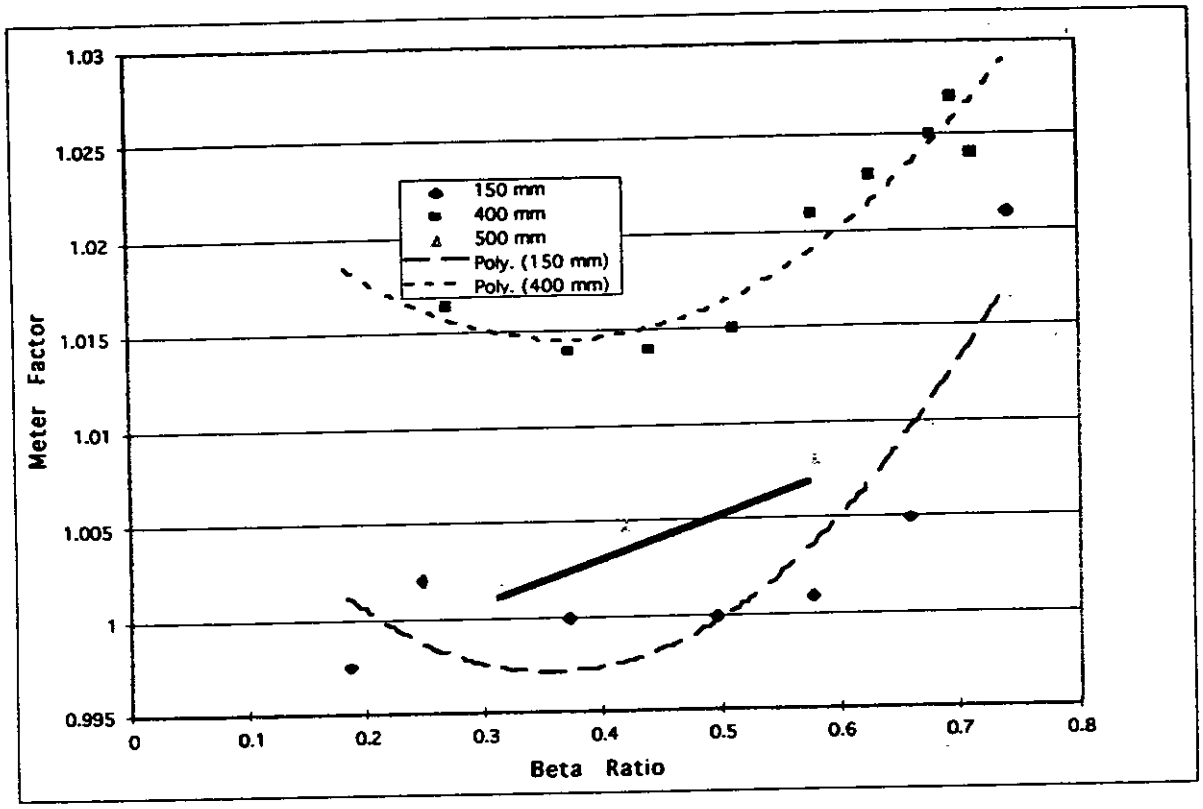

Figure 7: Kaybob Data Compared to Other Field Calibrations

Figure 7 presents data collected on all the meter runs and beta ratios tested. The meter factor is shown as a function of beta ratio. For reference, data collected by CPTC on 150 mm and 400 mm orifice meters in previous in-situ proving projects is presented along with the 500 mm data collected with the Kaybob prover. Apparent is the similarity of the general slope of the beta ratio curve for the field meter tests. However, the value of the meter factor varies with each test case.

For the Kaybob meters, the maximum factor is approximately 0.8% for a beta ratio of 0.58. The Venice 400 mm orifice meter had a factor of approximately 1.7% for the same beta ratio while the field-tested 150 mm runs had factors of approximately 0.2%. All of these different size runs were in-situ proven using similarly designed proving systems. However, the installation and operation of each orifice meter was different.

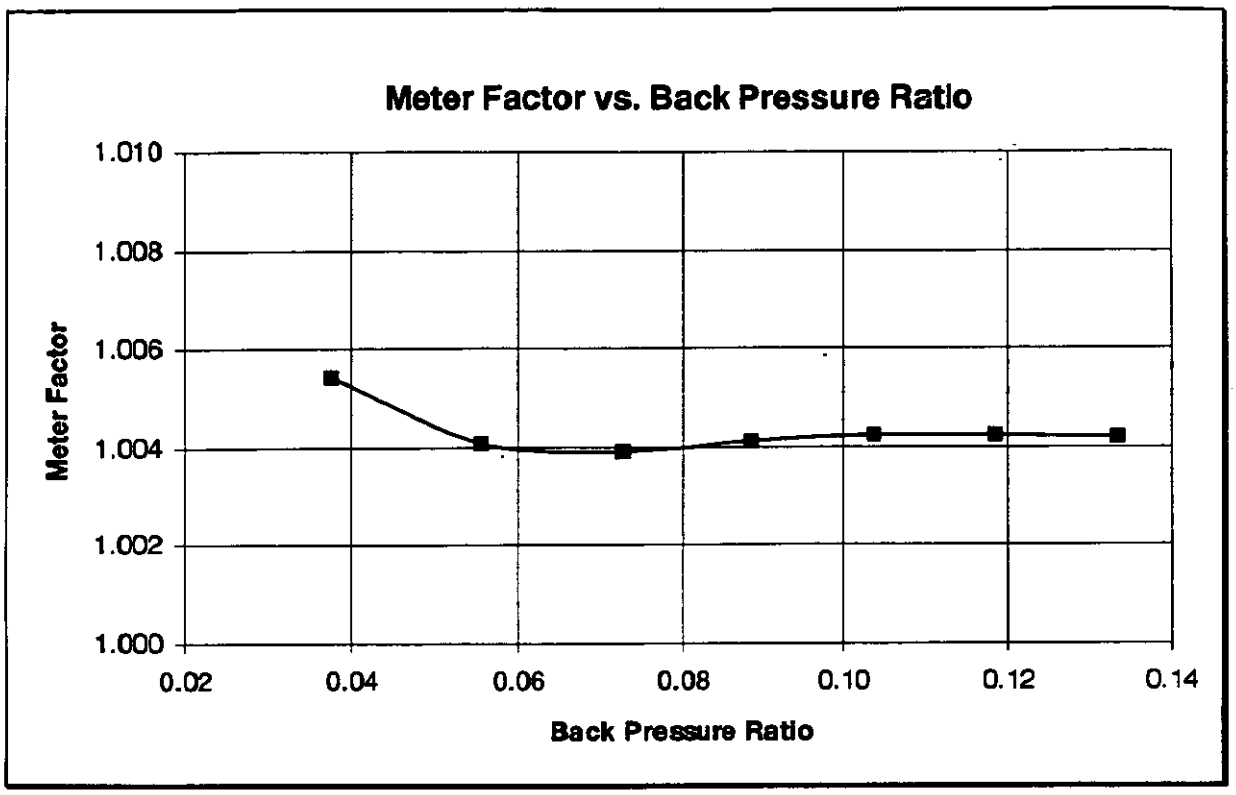

Figure 8: Results of Back Pressure Ratio Test

Figure 8 shows the data collected for the choking pressure differentials for the sonic nozzles. The test demonstrated that nozzles of the design used at the Kaybob facility may be operated with only a 6% pressure drop.

CONCLUSION

1. In-situ proving of large diameter orifice meter runs is achievable with today's technology. The application of in-situ proving is allowed for in orifice meter standards and can be applied to insure that the meters are functioning correctly.

2. Properly conducted, proving results in reduced orifice measurement uncertainty by removing unknown installation effects. The application of in-situ proving at the Kaybob facility has lowered the orifice measurement uncertainty to 0.42% from the pretest estimate of 0.76%.

3. The Kaybob meters displayed the same beta ratio effect as displayed by the recent installation effects work and previous in-situ proving projects.

4. Sonic nozzle provers of the design used may require less pressure drop than currently specified in standards. Testing has shown that a 6% pressure drop from

the nozzle plenum pressure is sufficient to obtain sonic flow at the throat of the nozzle.

FUTURE WORK

The authors can offer no definitive proof for the cause of the meter factor variation with beta ratio at the Kaybob meters, but hypothesize that it is the effect of either the upstream installation effect and flow conditioning device or the surface finish of the orifice meters. Tests are planned, which should be conducted by year end, that will either confirm or deny this hypothesis.

Additional tests using higher beta ratio plates will also be conducted to determine if the meter factor continues to increase with increasing beta ratio.

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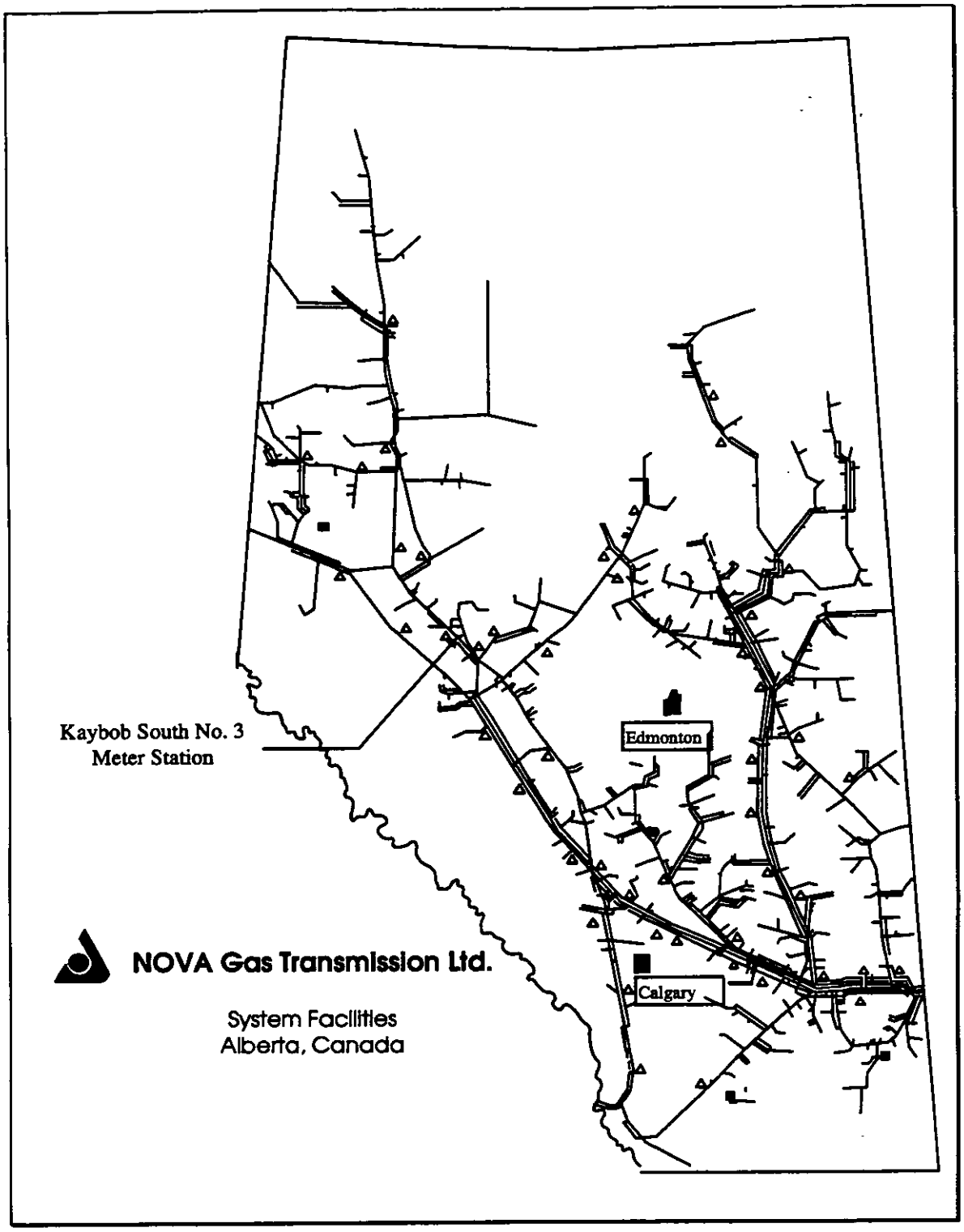

Figure 9: Location of the Kaybob South #3 Meter Prover

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North Sea FLOW Measurement Workshop 1995

Paper 4:

IN-SITU CALIBRATION OF FLARE GAS FLOW METERING SYSTEMS

1·4

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IN-SITU CALIBRATION OF FLARE GAS FLOW METERING SYSTEMS

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FORCE Institute, Division for Mechatronic and Sensor Technology

SUMMARY

The use of gaseous tracers permits efficient and reliable measurements of linear flow velocity of gas in flare systems under normal production conditions and covering the full range of flow rates.

The method is based upon the international standard ISO 4053/IV. A small amount of radioactive gas is injected into the flare gas stream, and the transit time for the tracer cloud between two radiation detectors outside the pipe is recorded.

Since 1983, FORCE Institute has carried out yearly measurements on all flare gas systems on Danish offshore platforms.

Flow velocities ranging from a few centimetres/second to more than 100 metres/second are covered using the same instruments and set-up.

The accuracy obtained depends on practical possibilities for injection, the available length of measuring distances, and the stationarity of the flow. Under typical conditions an accuracy better than ±1% is obtained.

The most commonly used gas tracer is the noble gas krypton as the Kr-85 isotope.

INTRODUCTION

Gas flaring in offshore installations represents a source of loss of energy making it important to operators and authorities to monitor the amounts of flared gas. In some countries the flare gas is subject to CO_2 tax. Flow metering systems are installed on some but not all flare systems.

In situ control and calibration of flare gas metering systems or in situ measurements of flare gas flow where no meters are installed can be performed by the gaseous tracer method without affecting the normal production and covering the large dynamic range of flow rates.

The concept of tracers implies the addition to a main flow stream of a small amount of a substance that flows with the main stream without distorting the flow. Measurements of variation with time of the tracer concentration reveals information about the main stream.

Radioactive tracers are isotopes of different elements in suitable chemical forms. Radioactive tracers can be measured in very small concentrations, and since the natural occurrence is none or very small, the signal to noise ratio for measuring radioactive tracers is very favourable.

METHODOLOGY

The gaseous tracer method yields the equivalent piston flow linear velocity of the gas flow in the pipe without any constraints regarding flow regime under the conditions prevailing for flare gas flow.

For calculation of the volumetric flow rate only the cross section area of the pipe is to be known. In order to give flow under standard conditions the temperature and pressure must be measured, and for conversion to mass flow the composition or density of the gas must be determined. These process parameters are often monitored by calibrated instrumentation.

The method is based on the international standard ISO 4053/IV, /1/. A small amount of the radioactive tracer is injected instantaneously into the flare gas flow through e.g. a valve, representing the only physical interference with the process. Radiation detectors are mounted outside the pipe and the variation of tracer concentration with time is recorded as the tracer moves with the gas stream and passes by the detectors.

The measuring principle is illustrated in figure 1.

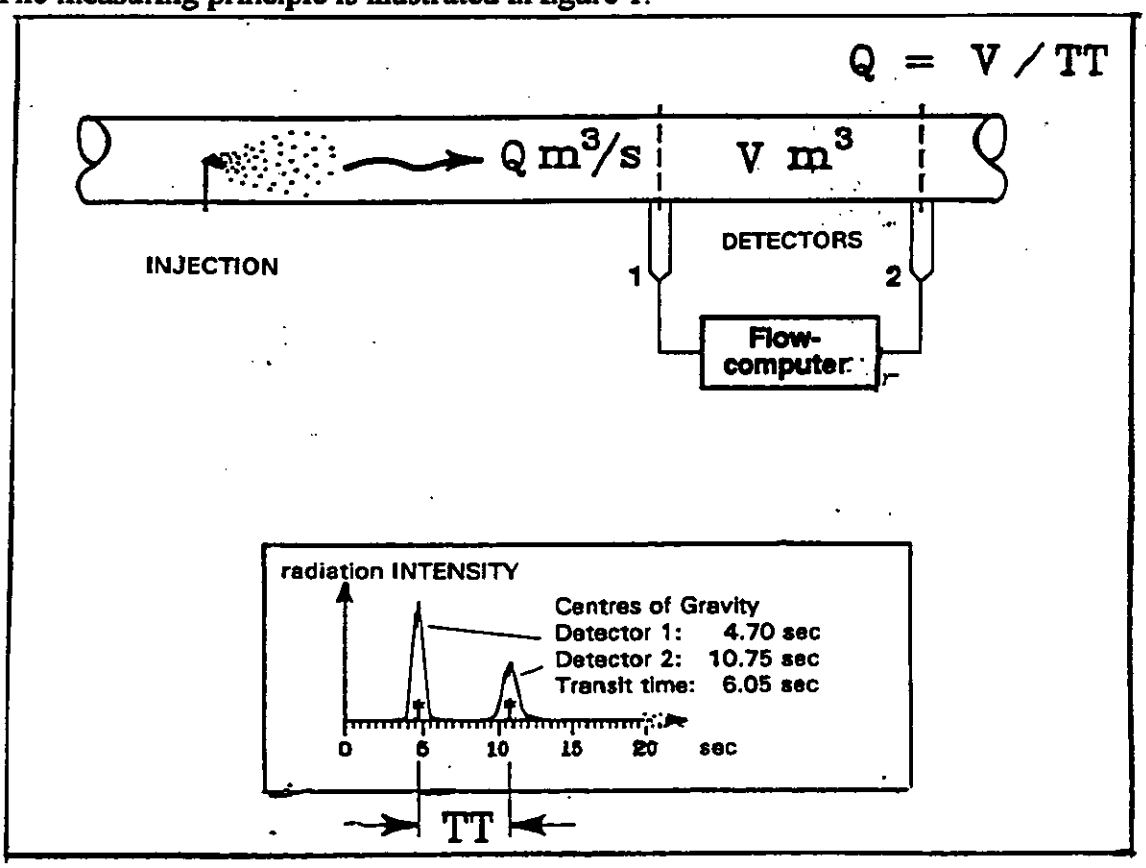

Figure 1: The principle of tracer measurement of flow by the transit time method.

Using the concentration versus time functions the mean value of the transit time from injection to each detector is calculated from which the mean transit time between 2 detectors is readily found. The linear velocity is found by simply dividing the distance between the detectors with the mean transit time.

Three detectors are normally used allowing for identification of flow variations during measurements. Such variation may occur even though the duration of each measurement is short, especially at low flow velocities. Distances between detectors are typically 25 - 50 meters with a total of 60 - 100 meters from the first to the last. The distance from the injection point to the first detector must be long enough to ensure mixing of the tracer over the full cross-section and depends of the possible presence of valves, bends etc. Normally 50 - 100 times the diameter of the pipe is required for optimum accuracy.

An example of actually recorded transit time functions is shown in figure 2.

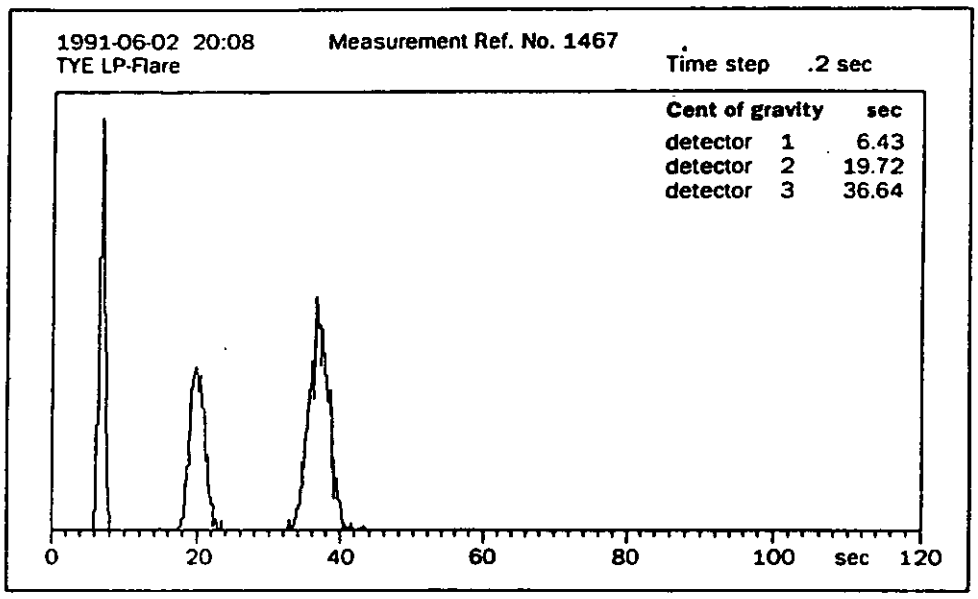

Figure 2: Recording of tracer concentration versus transit time

INSTRUMENTATION

The instrumentation for the gaseous tracer flare flow measurements consists of 3 units:

- an injection unit with tracer storage
- a package of 2 - 3 individually operated radiation detectors
- a control, supply and data registration unit including PC for on site data treatment.

A block diagram of the system is shown on figure 3.

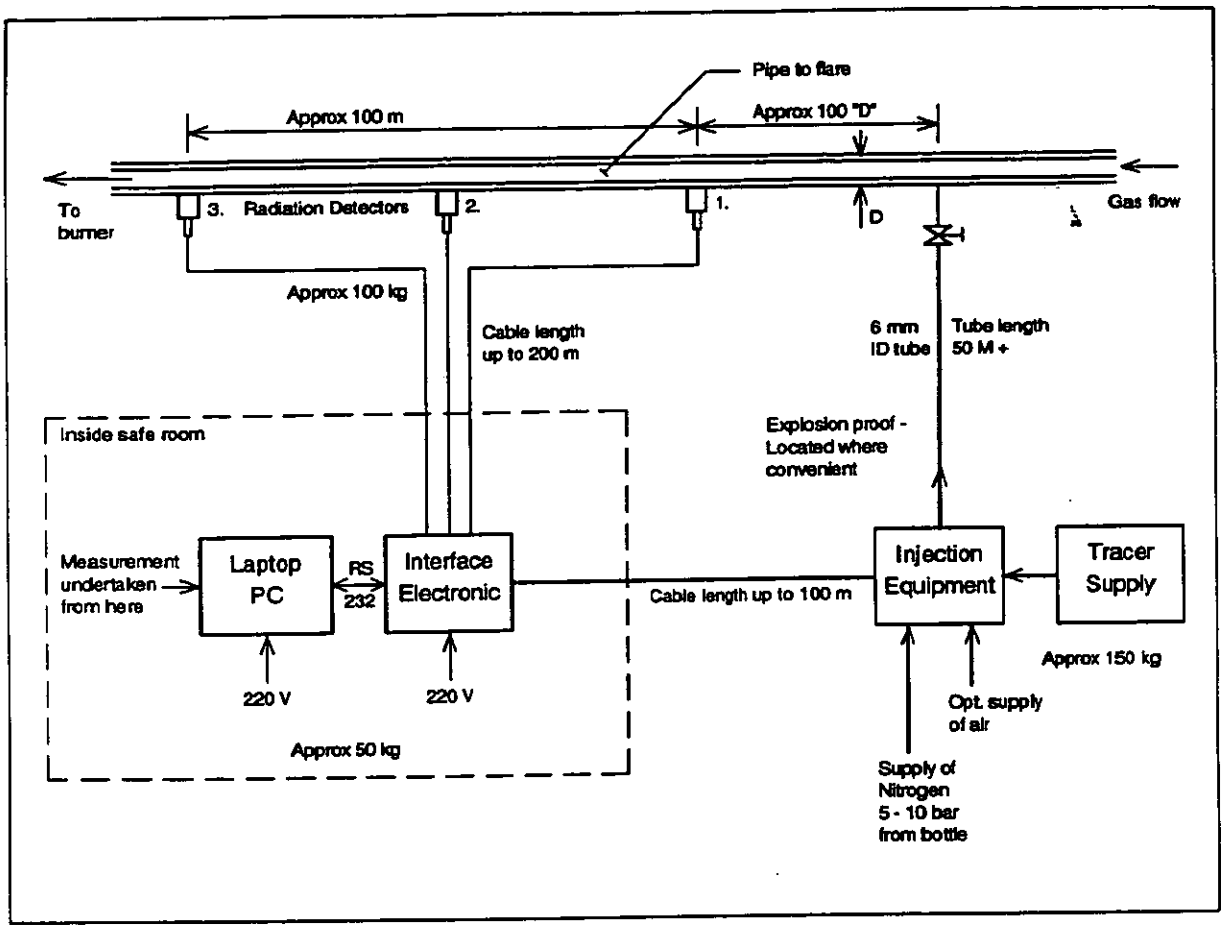

Figure 3: Block diagram of instrument set-up for gaseous tracer flow measurement

Injection unit

The injection unit undertakes injection of a short tracer pulse into the flare pipe. Our newest version was constructed during 1995 to meet increasing demands for fast and safe operation. The unit functions as follows:

The desired amount of tracer is metered off in a small chamber, which is subsequently flushed with a stream of nitrogen, through an injection tube with a length of up to 50 m and into the flare pipe, through a suitable inlet.

The flow and maximum pressure of nitrogen is adjustable to ensure optimal injection at the particular conditions. Typically the injection flow is approx. 2 litres/sec. and the travel time less than a second. By continuing the nitrogen carrier flow for 1 to 3 seconds after the pulse has entered the pipe line, residual tracer in the geometry through which injection is carried out, is removed, thus avoiding a long tail on the tracer pulse caused by slowly entering the gas stream. A total of 5 to 10 litres are injected, which is totally insignificant compared to the flow measured.

The pulse duration is shorter than 0.05 seconds when the pulse leaves unit. Despite dispersion in up to 50 m of tube leading to the injection point, the broadening of the

pulse is low compared to that caused by the dispersion in the flare pipe and will thus not degrade measurement accuracy significantly. However, for maximum accuracy and lowest tracer consumption, the injection tube should be kept as short as possible.

Depending upon the geometry of the available injection point, the velocity of the injection jet will typically be so high that impact mixing occurs and enhances the radial mixing, causing the necessary distance from injection point to first detector to be shorter. Under optimal conditions a mixing difference of less than 0.5%, corresponding to a far less error in the flow measurement, can be achieved within considerably less than 100 pipe diameters.

Tracer is kept in a lead shielded steel cylinder being able to hold 600 GBq of Krypton-85 tracer, which is sufficient for between 150 and 2000 single measurements. The tracer consumption depends strongly upon the flow being measured (consumption roughly proportional with flow) and geometry of injection point and pipe (considerable variation).

The injection unit operates unmanned and is remotely controlled through up to 100 m cable leading to the controller and data processing unit, located in a safe room. The tracer filling and injection processes are fully automated and supervised from the instrumentation in the safe room. The electrical parts of the injection unit, being limited to magnetic valves and cabling for these, are in explosion proof versions.

Radiation detectors

The radiation detectors are highly sensitive 2" sodium iodide scintillation detectors in pressure tight, explosion proof stainless steel housing. The detectors are equipped with lead collimators in order only to detect radiation from a narrow field in the longitudinal direction of the flow. They are readily mounted out side the flare pipes, e.g. by roping. Power is supplied from and data transmitted to the controller unit trough up to 200 meters of cables.

The radiation measured through the pipe wall is proportional to the tracer concentration in the pipe cross section at the detector.

Controller unit and data treatment

The controller unit is placed in a safe area with supply of power.

Injection is controlled by a PC.

Power supply for detectors and primary registration of data for radiation detection is performed by a dedicated data registration unit, which transfers data to the PC for further treatment.

The detectors measure tracer concentration with a sampling time suitable for getting sufficient time resolution in the concentration versus time function. Sampling times down to 0.025 second can be selected.

The mean transit time from injection to each of normally 3 detectors is calculated as the centre of gravity for the concentration versus time distribution. Simultaneously the standard deviation of the mean transit time is calculated. Transit time between detectors are calculated and from measured distances between the detector the linear velocities and their standard deviation are automatically determined. A computer printout as shown i figure 4 gives the measurements results immediately, allowing for on site preliminary assessment of results and decision about further measurements.

```
--- flow measurement, ref.  1145 ----------------------------------------

FLARE-FLOWMÅLER-KALIBRERINGER 1995


95.05.23 14:38:57

tracer amount (units)          0.00
analysis delay (sec)           0.00
basic sample int. (msec)      25
dist. d12, d23, d13 (m)       28.35     53.10     81.45
backgrounds d1-4 (cps)         6.36      3.31      3.48   2771.86

data have been reduced.
number of data points        512
final sample interval          0.025
duration (s)                  12.800


--- peak search ---------------------------------------------------------

window before (# smpls)       10
window after  (# smpls)       20
significance (# st.dev.)       3.50

dataset   cen.gr.     st.dev.    rst.dev.     first      last  =>   time
   #        #          #          %           #          #          s

   1      18.16      0.1708      0.940         6         41       0.454

   2      60.88      0.2830      0.465        47         87       1.522

   3     140.82      0.3655      0.260       123        172       3.520


--- velocities ----------------------------------------------------------

pair    velocity     st.dev.    rst.dev.
          m/s         m/s         %

 1-2    26.5473     0.2054      0.7738

 2-3    26.5709     0.1537      0.5783

 1-3    26.5627     0.0874      0.3289

--- end -----------------------------------------------------------------
```

Figure 4: Computer print out of tracer velocity measurements.

CONTROL AND CALIBRATION EXPERIENCE

Ever since 1983 yearly calibrations have been made on 4 flares on Danish offshore platforms. Measurements have also been made on Danish and Norwegian onshore gas treatment facilities and oil refineries.

The permanently installed flow meters controlled have been of the thermal, ultrasonic, and orifice types.

The gaseous tracer method performed by the FORCE Institute yields the linear flow velocity of the flare gas. Data for inner pipe diameter is available from the plant operators. Supplementary measurements of temperature, pressure, and density and/or mole-weight are performed by plant operators or flow meter service operators.

The typical test procedure involves the following steps

- transport of equipment (ship) and personnel (helicopter) to platform
- arrange necessary working permit
- install injection unit at first injection site and detectors at measurement positions, measure distance between detectors
- install controller unit in safe area
- hook up cables and hoses
- test of instrumentation
- measurements at present calibration at various flow rates
- adjustment of metering system } may be repeated
- repeated measurements } may be repeated
- install on next flare or ship equipment.

Normally one flare on a platform may be calibrated over two working days for optimum accuracy, but more flares on the same platform reduces the time for instrumental set-up. If the demands for accuracy is limited the number of measurements per flow rate may be limited both before and after adjustment of the meter, which will to some degree cut down time consumption.

For the highest flow rates each tracer measurement only lasts 15 seconds with a repetition frequency of less than 40 seconds thus limiting the amount of gas being flared during the measurement procedure.

DYNAMIC RANGE AND ACCURACY

The methods covers the full dynamic range of linear velocities from a few centimetres/second to over 100 meters/seconds with one and the same instrumental set-up. Only the amount of tracer used per injection is varied.

The main sources of error which define the accuracy are counting statistics in tracer concentration measurements, the dispersion of the tracer cloud in the flare gas stream, and the stationarity of the flow during measurements.

Under typical conditions and flow rates up to 50 meters/second the accuracy have been experienced to be considerably below ±0.5%.

At higher flow rates the dispersion of the tracer and the lower limit for time resolution of the concentration versus time distribution limits the accuracy to better than ±2%.

At lower velocities the unstationarity of the flow during measurements may set the limit. This possible effect in controlled using three detector and observation of any differences in the velocity determined from different pairs of detectors.

The geometry of the injection point is very important. Thus, injection into a flare drum should be avoided as it will increase the dispersion and dilution of the tracer gas and thereby decrease the accuracy unless prohibitively large amounts of tracer are used to compensate.

Repeated measurements, which is feasible due to the efficiency of the method and the equipment, are most often applied, and improve the overall accuracy, when optimum performance is required.

SAFETY

The choice of tracer gas for the measurements is Krypton-85. It has a long half-life so that it can be stored for application when needed. In is a noble gas which is chemically inactive giving a low radio toxicity as it is readily removed in case of accidental contamination.

Transport and handling of the radioactivity follows internationally accepted regulations and is conducted be personnel from FORCE Institute under the local national radiation health authorities.

The amounts of isotope used is limited due to application of highly sensitivity radiation detectors. The amounts cause no significant radiation exposure to platform personnel, and normally no rope off is required when performing the tracers flow measurements. Even at peak tracer concentration the radiation level at the pipe surface is less than 1 - 2% of the accepted dose rate of 60 μSv/h, which is accepted just out side roped off areas during x-ray testing of weldings. The radiation detectors used on the other hand are so sensitive, that x-ray testing should not be performed within 200 meters from any detector.

Krypton-85 is produced from nuclear waste by concentrating in reprocessing. If not reprocessed and used it would be discharged to the atmosphere anyway, and the amount used in flare gas flow measurements are thus totally insignificant compared to the amount being present in the global environment.

CONCLUSION

The use of tracer methods for flare gas flow measurements has proved in many years of practice to be an efficient method for flow meter control and calibration and flow assessment. The measurements are performed in situ under normal conditions without interrupting the production.

The dynamic range and the accuracy obtained have been shown to be of great practical value, and the measurements are fast, reliable and safe.

REFERENCES

/1/ International standard ISO 4053/IV, "Measurements of gas flows in conduits - Part IV: Transit time method using radioactive tracers"

Main Index

North Sea FLOW Measurement Workshop 1995

Paper 5:

WHY WE USE ULTRASONIC GAS FLOW METERS

1·5

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Organised by:
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Norwegian Society for Oil and Gas Measurement
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WHY WE USE ULTRASONIC GAS FLOW METER

Presented at North Sea Flow Measurement Workshop , Lillehammer Norway 24-26 October 1995

Author: Reidar Sakariassen, Statoil

SUMMARY

Statoil has more than six years experience with multipath ultrasonic gas flow meters and has been using such gas flow meters for fiscal purposes offshore for past two years.

This paper will present those projects where fiscal ultrasonic meters are installed and give reason for the selection.

Further, experiences from the operation of meters from 12" to 24" are reported, highlighting the utilisation of the information which is unique for ultrasonic flowmeters: Information about velocity distribution in the pipe and velocity sound.

Some test and calibration results are also presented.

1 INTRODUCTION

Statoil decided back in 1988 to investigate the possibilities of introducing simpler fiscal metering equipment than the conventional multirun orifice systems on a riser platforms to be tie-in points for new pipelines. Up till now it has been a request to fiscally meter all streams into, out of and between the different parts of the pipeline system. In some cases this also require bi-directional metering systems.
Ultrasonic flow meters turned up to be the solution with the best potential for the future.

Currently eight ultrasonic meters are installed and running offshore. Two of them are part of the Sleipner/Zeepipe project and six of them are part of the 16/11-S/Europipe project. They are all accepted by Norwegian Petroleum Directorate (NPD) as fiscal meters.

We plan and expect more meters of this type to be installed offshore, in the near future.

Over the passed 6 years Statoil has therefore gained a lot of experience from laboratory testing, from monitoring of meters in operation and from research and development.

2 WHY ULTRASONIC FLOW METERS

2.1 General

2.1.1 Size and money

The main driving force behind our search for simpler metering system was saving of money.
With the information we had six years ago, the potential was an enormous reduction in size and weight when using ultrasonic meters instead of conventional orifice plates.
The reason is that for our operational conditions, the measuring range for a single meter run with ultrasonic meters was three times that of the orice meter run of the same diameter and the requirement for the length of straight pipe.
Figure 1 illustrates this point for a bidirectional system.

The cost savings on offshore platforms by reduced weight is estimated to 300 - 800 kNOK pr.ton depending on type of platform.

2.1.2 Accuracy

From the meter specification the accuracy seemed to match that of orifice meters.
We think we can conclude that through our tests this is confirmed for the meters that we have put in operation provided the meters are flow calibrated and eventually corrected.
We have however performed a number of investigations on installation details and are aware of the result from the Ultraflow Project [1]. There are indications that more work need to be done in order to obtaine the correlation between design of meter, type of flow and pipe disturbancies and meter error.

2.1.3 Information and diagnostics

The ultrasonic meters can offer valuable additional information about the flow velocity and velocity of sound. This information can partly be used for diagnosis of the condition of the meter and partly as valuable information about what is going on inside the pipe.
In addition, the meters themselves have built-in diagnostics which can tell the operators when and why the condition of the meter is deteriorated.
Our experience is that such additional information is of high importance and enables the operator to evaluate the condition of the meter at any time.

2.1.4 Redundancy in one meter

The multipath design can, in addition to improve accuracy, also be ragarded as a redundant meter provided the meters are so designed that it continue to meter with one or more pair (up to maximum all except one pair) fails and there is possibility to replace a malfunctioning pair during normal flow conditions.
Our experience is that this is the case.

2.2 Sleipner/Zeepipe project

Sleipner is in addition to being a production platform also a tie-in point between the Statpipe and Zeepipe transportation system.
Sleipner's own production is metered by a conventional orifice metering system. The requirement to also fiscally meter the flow between the two transportation systems required bi-directional metering systems.
After thoroughly evaluation and testing including a test period of 6 month with a 24" meter temporarily installed at 16/11-S [2] it was decided to go for an ultrasonic solution.

The concept consists of one single bi-directional 12" meter run and uni-directional 24" meter run in parallel. The ultrasonic meters fitted into the piping that anyway was required.

The reason why a single run concept for one direction was selected and accepted was partly because of space limitation, partly because of the built in redundancy in the meter and partly because of the possibility to estimate the the quantity by means of other meters in the transportation network.

The 12" meter has been in operation since September 1993 after being accepted by NPD. The 24" will probably be in operation from summer 1996 when Troll start production.

The investment cost saving by using this ultrasonic system compared to conventional bidirectional orifice station was found to be between 100 and 150 MNOK.

2.3 16/11-S/Europipe project

The excisting riser platform 16/11-S was appointed to be the tie-in point between the Zeepipe, Statpipe and Europipe transportation system.
This required the installation of six new fiscal metering sytems at a small excisting riser platform: The flow in each of three incoming pipelines could be splitted in two outgoing pipeline simultaneously.See figure 2.
Installation of six conventional orifice stations each having a capacity of approximately 40 MSm^3/d and a required turndown of 1:30 for a design pressure of 172 bar would be almost impossible to install concerning the space required and the additional weight.
Based on experience from previous tests and the Sleipner/Zeepipe project it was decided to install six 20" single meter run systems with ultrasonic flow meters.

The reasons for selecting and accepting single run systems was partly because of space limitations,the built in redundancy in a single meter, the excisting possibility of by-pass piping in case of need for repair requiring no flow through the meter and the possibility for estimating the quantity in case of meter malfunctioning or by-pass flow for other reason.

The meters was put in operation summer 1995 after being accepted for fiscal metering by NPD.

No detailed estimate of cost savings by using the ultrasonic concept instead of orifice system was done. It was uncertain how many and how big additional moduls were required on the platform to create sufficient space for conventional meter systems. However, a brief estimate was a cost saving 150-300 MNOK compare to installation of conventional orifice system.

3 EXPERIENCE

3.1 Accuracy and calibration

All meters installed up til now have been individually calibrated in flow laboratory.
Examples of results from such flow calibrations are shown in figure 3 for a number of 20" meters.

Additional tests have been performed to study the accuracy under varying conditions like pressure and temperature and also under different installation conditions.
Figure 4 shows example of calibration results obtained at different pressures for a 12" meter.

Smaller meter like 6" meters turns out be be less linear than bigger meters. The reason might be that the flow pattern inside the meter body is not as ideal as assumed. Example of calibration result of a 6" meter at different installation condition is shown in figure 5.

Calibration results are used to determine correction factors for the individual meter.

Also, after the meters are installed, they are continuously monitored and compared with other meters.

It is a goal for the manufacturer and the user to rely on dry calibration. Our experience from our calibration program is that individual flow calibration before installation is necessary to obtain and verify sufficient accuracy in volume flow measurement to obtain an uncertainty of less than 1 % on mass flow.

3.2 Information and diagnostics

To understand the possibility that a ultrasonic flowmeter offers concerning checking, monitoring and utilisation of if information, it is worthwile to briefly describe some basic elements of the principle. The basic equation which relates the transit times measurement to the velocity,v, for a chord is:

$$v = \frac{L^2}{2X} \cdot \frac{t_2 - t_1}{t_1 \cdot t_2}$$

where

L is the length of the acoustic path between the transducers in a pair
X is the axial distance between a pair of transducers
t_1 and t_2 is the transit time in downstream and upstream direction respectively between the transducerfronts

t_1 and t_2 are determined from measured times between electronically transmission of signal till electronically detecting received signal minus delay times in the transducers and electronics and delays caused by detection method. Typical delay time in the transducerpair and electronics is in the order of 10 µs and a difference in upstream and downstream direction of typically 0 - 200 ns. The delay caused by signal detection method is in the order of 10 - 20 µs.

The most critical term is (t_2-t_1), also denoted as Δt. Δt is very much affected by the small difference in the transducers' delay times in the two directions. Errors in Δt results in zero error.

Typical velocity of sound (or the equivalent terms L/t_1 and L/t_2 in the above equation) in natural gas is between 350 - 420 m/s depending on composition, pressure and temperature.
For a 12" meter with chord design the transit time are in the order of 2000 μs and the Dt at 1 m/s approximately 2.2 μs.

Reporting of the individual gas flow velocity and velocity of sound (see figure 6), useful information is available for monitoring, check and verification of the stability and condition of the meter.

3.2.1 Monitoring of gas flow velocity for check purposes

In a mulipath meter more individual flow velocity are measured.
For a meter installed in a fixed geometry, the relation between the individual velocities are constant over time and velocity range.

Under this assumption, monitoring the individual velocities chronologically and also plotted as function of average flow velocity will indicate the stability of factors affecting the time measurement. Error in the most sensitive term, Δt, will result in a zero error for the actual chord.

Figure 7 shows an example of such a monitoring for a 12" meter installed offshore over a period of 7 months. In the same figure is also indicated what would be observed should a change in Δt of 200 ns occure in chord A: As the vlocity is approaching zero, the deviation in velocity from chord A relative to the average velocity will increase. The resulting change in the meter's flow readings is also indicated. As can be sen, this kind of monitoring will reveal drift in the meter caused by drift in the transducers' "delta delay times".
No other single flow meters offer similar possibility.

In some cases, however, the velocity distribution is not fixed even when the meter is installed in a fixed geometry. In such cases where there is a rather complexed relation between the velocity, the chronological monitoring or a monitoring of velocity distribution with flow velocity rather difficult to interpretate. In the next section such an example is given. An example is given in the next paragraph.

3.2.2 Monitoring of gas flow velocity for investigation purposes

In addition of being a valuable verification method, the information of flow velocity distribution can also give valuable information about the effect from certain pipe elements.
An example of such a case is the results from one of the installation at 16/11-S:

One of the streams is split in a tee-connection. The flowrates in the two branches are controlled separately.
When observing the gas flow velocity distribution in one of the meters chronologically or as a function of flow velocity, the distribution pattern was rather random. See figure 8a and 8b.
However, when plotting the flow velocity distribution between the chords as a function of the ratio

of flow in the two branches, the trend became quite clear as shown in figure 8c. Given this velocity distribution relationship, it is possible to continue the monitoring for revealing zero offsets in the future.

The example from 16/11-S indicates the possibilities that multipath ultrasonic flow meters offers in this respect. For example, 6" and 12" meters have been used at K-Lab to study the effect bends and flow control valves as well as the effect of installing flow conditioner behind bends and valves. Results from such studies will however not be presented here.

3.2.3 Monitoring of velocity of sound distribution for check purposes

In addition to the monitoring of the velocity and the velocity distribution which in essence is a monitoring of the stability of Δt measurements, the monitoring of the velocity of sound (VOS) is in essence a monitoring and verification of the absolute transit times measurements. It is two kinds of monitoring: Verification of the the closeness between the individual measured VOS and a comparison between measured VOS and a calculated VOS.

When gas is flowing through the meter the VOS from each chord normally is equal within certain limits. This indicate that the time measurement is correct. (No miss on the the period of received signal).
Figure 9 gives an example of such a monotoring indicating stable conditions over a long period of time.

The comparison between measured and calculated VOS is a bit more "tricky". We have based our calculated VOS, c_g, on the general thermodynamic relation:

$$c_g = \sqrt{\gamma\left(\frac{\delta p}{\delta \rho}\right)_T}$$

The expression $(\frac{\delta p}{\delta \rho})_T$ can be calculated based on the method for density/compressibility calculation from gas composition described in AGA Report No.8 or other similar method. The problem is that the exact knowledge of the gas composition at any time is normally lacking. In our systems, however, we are continously measuring operating density.

Our method for calculating VOS, c_c, is as follows:

$$c_c = c_g + A(p, T, \rho_m - \rho_g)$$

where

- c_g is calculated VOS from a fixed, nominal gas composition
- A is an expression dependant on p.T and ρ_m-ρ_g
- ρ_m is measured operating density
- ρ_g is calculated density from a fixed nominal gas composition at operating pressure and temperature

It is important that ρ_g and c_g is based on the same equation of state.

Figure 10 shows measured results compared with theoretical results based on AGA 8 rev. 85 and 92. All data are reduced to data at 100 bar and 7 °C.
Figure 11 shows the agreement between our calculated VOS and measured VOS. A change of 1 m/s in VOS affects the flow velocity measurement by 0.5 %. The uncertainty in our way of calculating the VOS is estimated to less than 1 m/s.
Revision -85 and -92 of AGA 8 differs. The measured results is in between, but closer to the -85 version.. Our field measurement is very close to measurement performed by laboratory measurement [3].
We believe this a very good method to verify the transit time measurement. It does not only allow for a check of the VOS measurements. It also allow for a cross check between two independently measurement, density and VOS.

3.2.4 Monitoring of VOS for research purposes

For the compositions we are deling with, it seems like there is a theoretical unique relation between density and VOS.
This relation can and has been checked out in our metering systems where the density is measured together with VOS.
Our conclusion so far is that the VOS can be as reliable for density determination as the densitometer itself.

Another use of the VOS measurements and distribution is to study temperature gradients in the pipe. For our most common operating conditions, the VOS drops about 1 m/s per °C drop. Provided the measurements of VOS are reliable, such measurements can give interesting information about the hydrodynamic taking place inside the pipe.

Paper will be hopefully be presented at other events descibing such findings.

3.3 Redundancy

From experience at flow laboratory with missing pair(s) of transducers it is verified that for 20" four path meter the additional uncertainty when all but one chord is working, is less than 0.2 %. With all but two chords working the additional uncertainty is less than 0.4 %.

Operating experience from Sleipner with replacement of transducer under flowing condition is fully possibly. There was no noticeable effect on the flow readings during or after the replacement.

Future operators should however be aware of the retraction mechanism and check whether it is accepted from a safety point of view by their company.

3.4 Installation hints

Two impotant consideration should be mentioned:

1. Flow control valve installed in the proximity to the meter might create ultrasonic noise unacceptable to the meter. This is most expelled with low (audible) noise valves.

2. The meter spoolbody should be thermally insulated. This is especially important when gass temperature is far from ambient, smaller meters and meters with deep transducer cavities.

3.5 Standardisation

The status concerning standardisation is that a ISO TR Working Draft [4] has recently been issued. It is for comment until the end of 1995.

4 CONCLUSION

With the knowledge about the the multipath ultrasonic flowmeters that we have obtained over the past six years, we still consider this type of meter as a meter for the future.

Because of the good relation we have had with different manufacturer, the technoly has improved and relevant and good verification procedures have been developed.

There is however still a nedd for more work to be done, especially on installation effects including effects of flow control valves.

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4. ISO/TC 30/WG 20 N 103 E:
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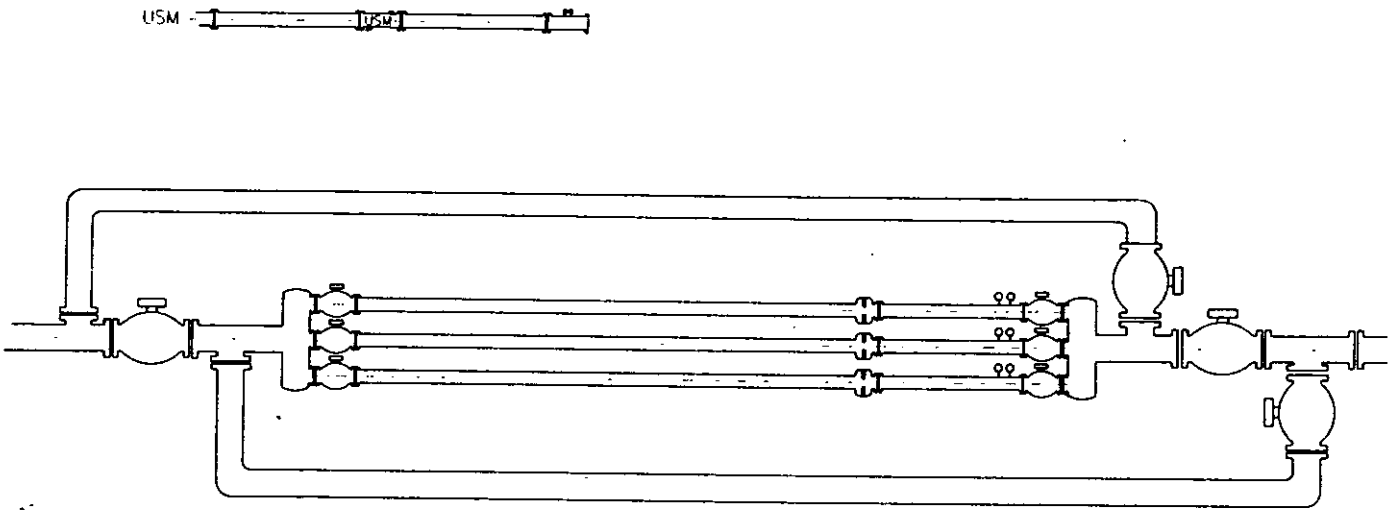


Fig. 1 Sketch showing potential difference in size between bi-directional USM and orifice system

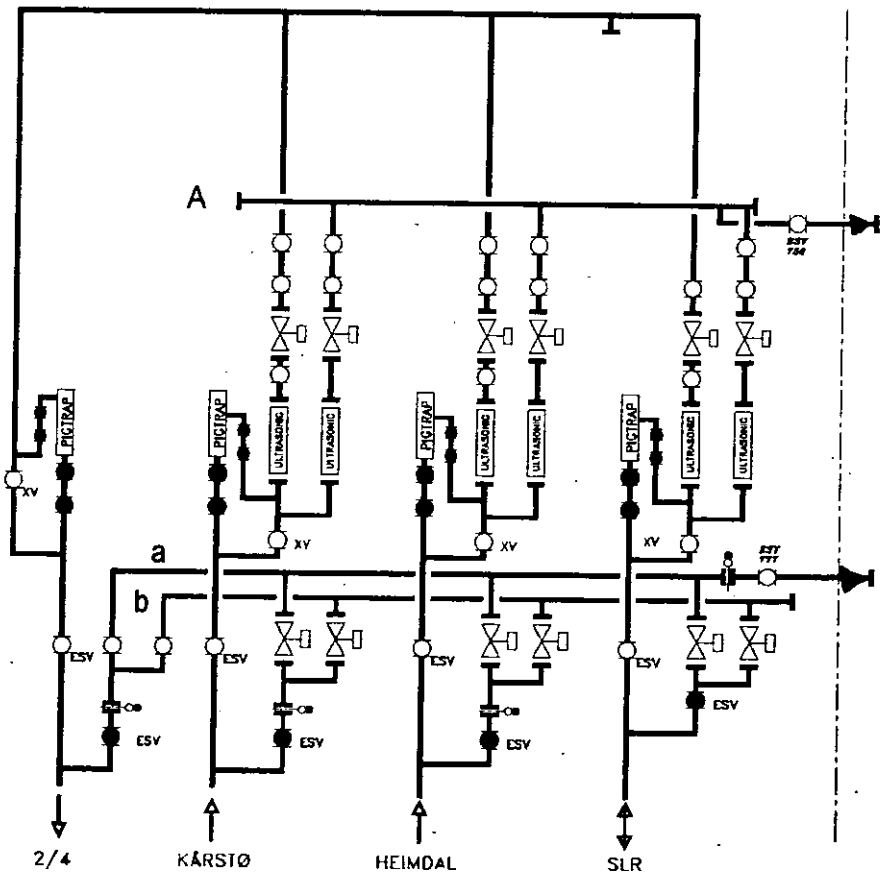


Fig. 2 Lay-out of metering concept at 16/11-S

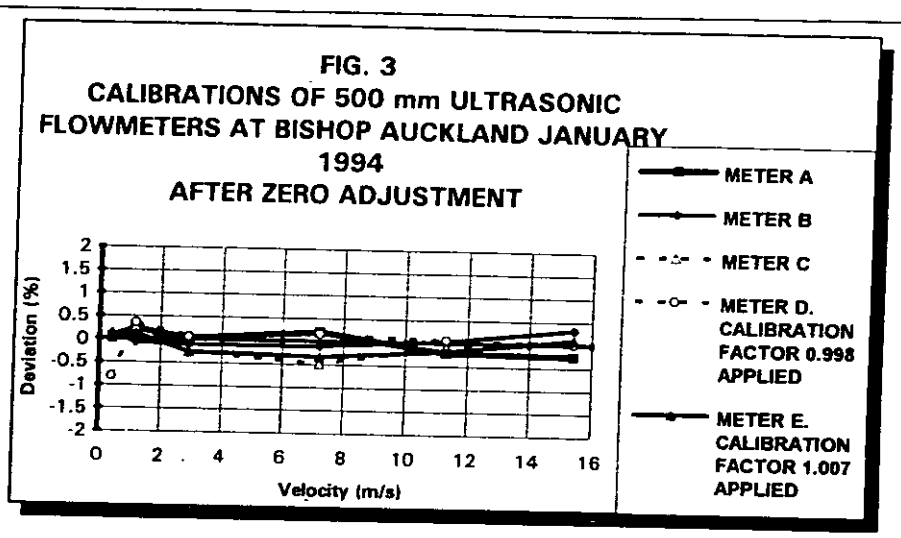


FIG. 3
CALIBRATIONS OF 500 mm ULTRASONIC FLOWMETERS AT BISHOP AUCKLAND JANUARY 1994
AFTER ZERO ADJUSTMENT
Deviation (%)
2
1.5
1
0.5
0
-0.5
-1
-1.5
-2
0
2
4
6
8
10
12
14
16
Velocity (m/s)
METER A
METER B
METER C
METER D. CALIBRATION FACTOR 0.998 APPLIED
METER E. CALIBRATION FACTOR 1.007 APPLIED

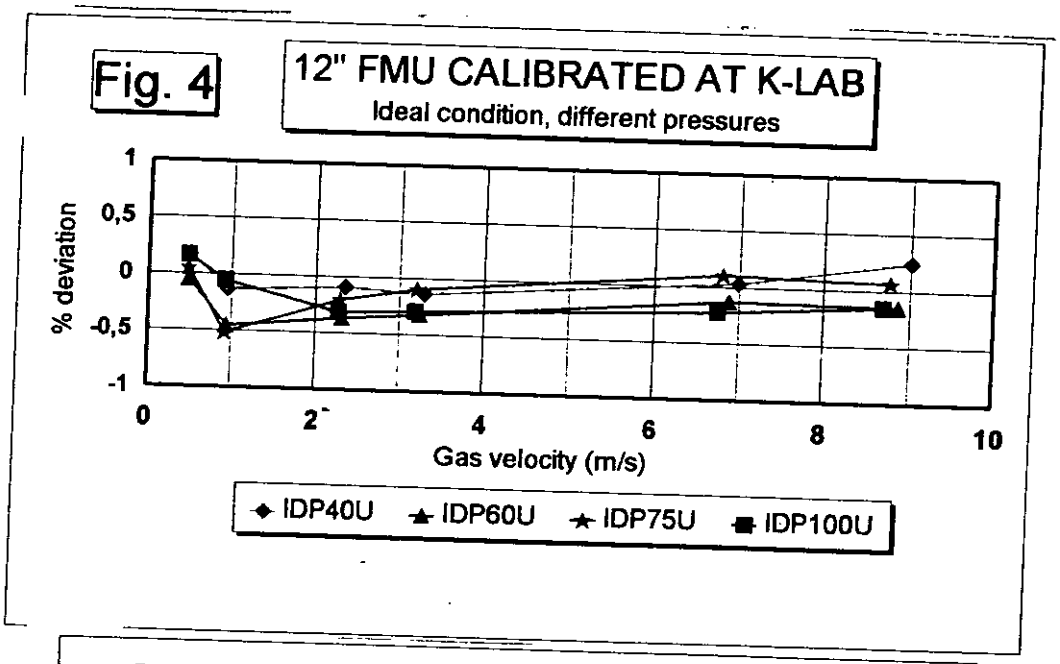


Fig. 4
12" FMU CALIBRATED AT K-LAB
Ideal condition, different pressures
% deviation
1
0,5
0
-0,5
-1
0
2
4
6
8
10
Gas velocity (m/s)
IDP40U
IDP60U
IDP75U
IDP100U

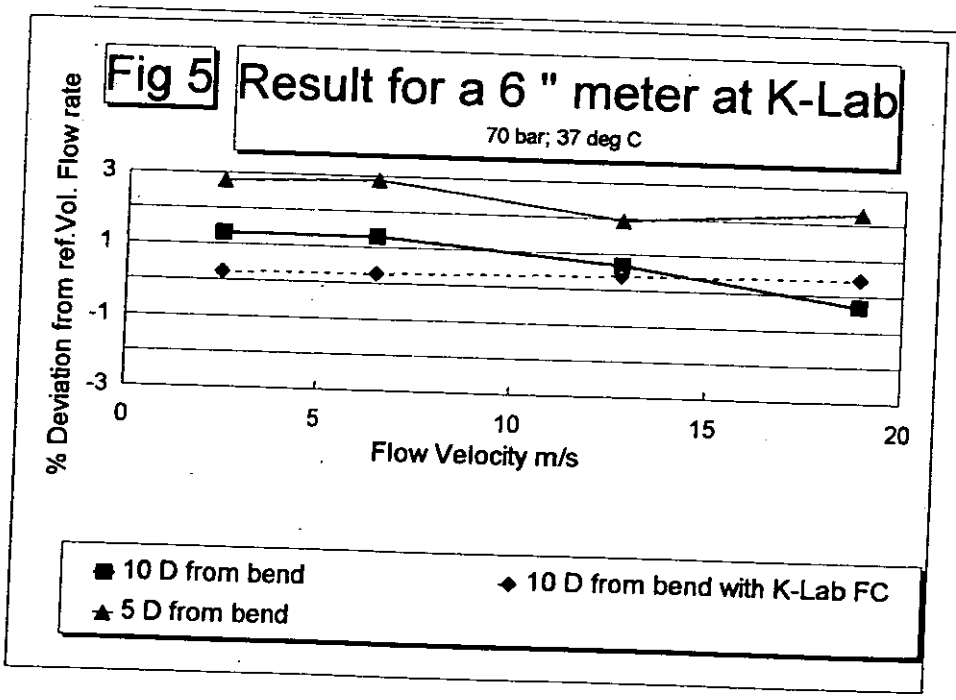


Fig 5
Result for a 6 " meter at K-Lab
70 bar; 37 deg C
% Deviation from ref.Vol. Flow rate
3
1
-1
-3
0
5
10
15
20
Flow Velocity m/s
10 D from bend
5 D from bend
10 D from bend with K-Lab FC

Fig. 7
12" USM at Sleipner.
Normalised gasflow velocities from each acoustic path logged daily over a period November 1994 till June 1995

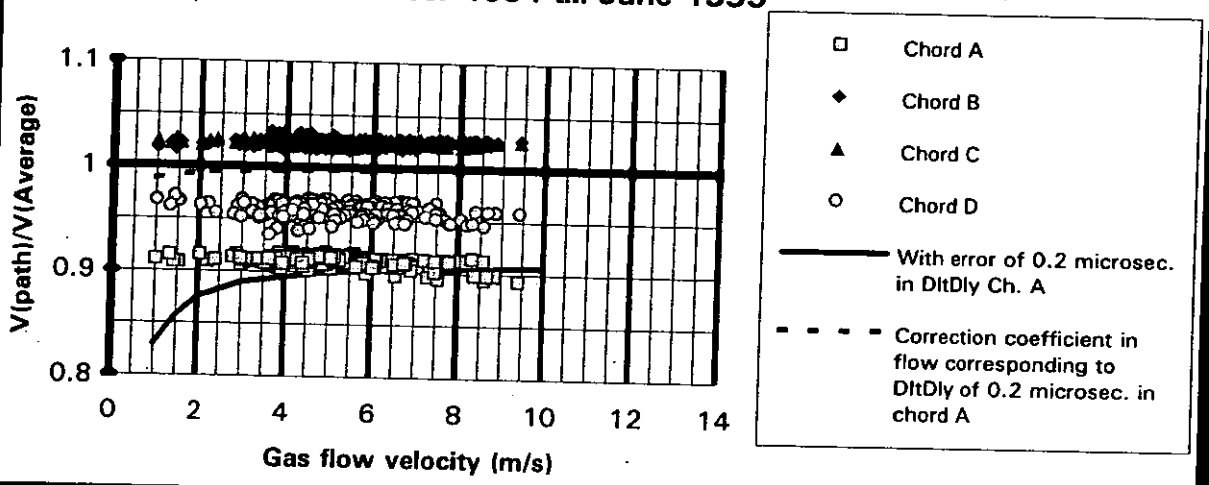


Fig 8 a

Normalised velocity v(chord i)/v(average) in A-meter chronologically monitored

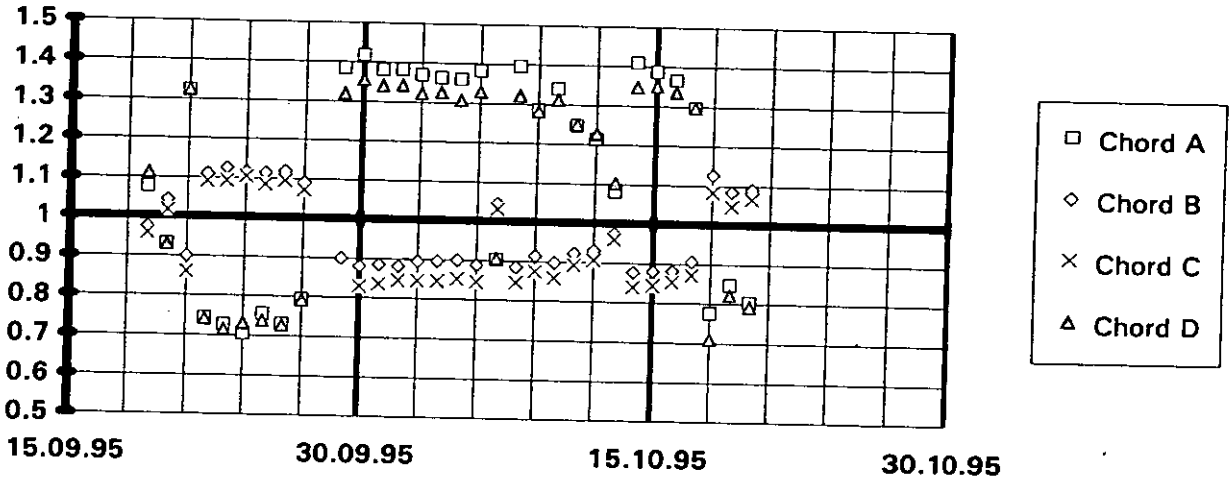


Fig 8 b

Normalised velocity v(chord i)/v(average) in A-meter as function of flow velocity

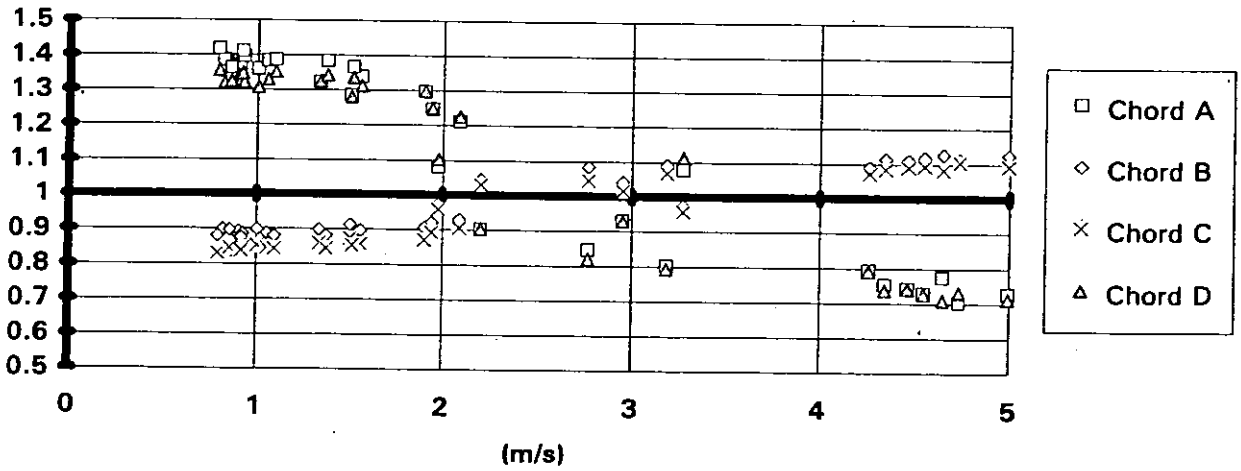
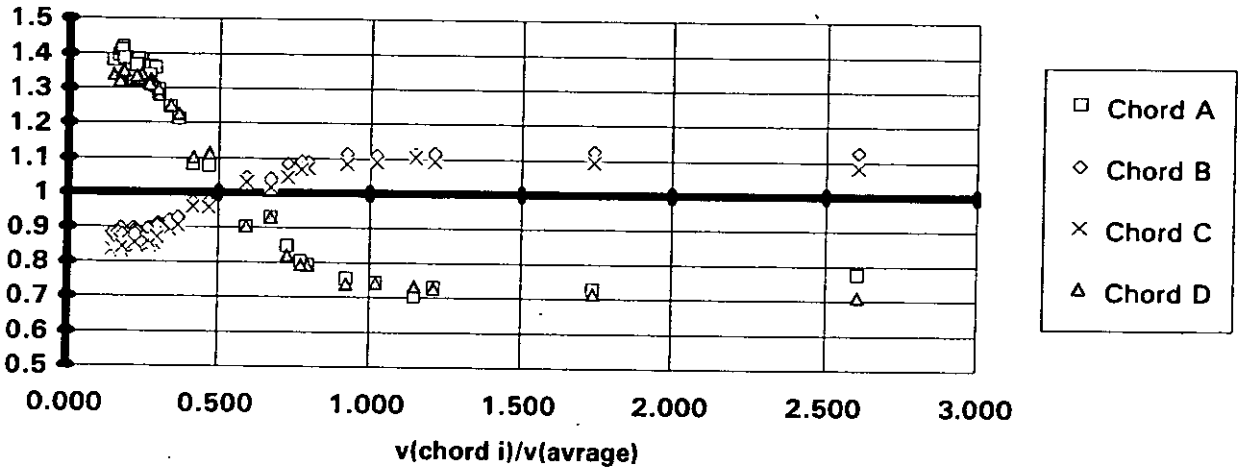


Fig 8 c

Normalised velocity v(chord i)/v(average) in A-meter as function of flow ratio between A and B meter



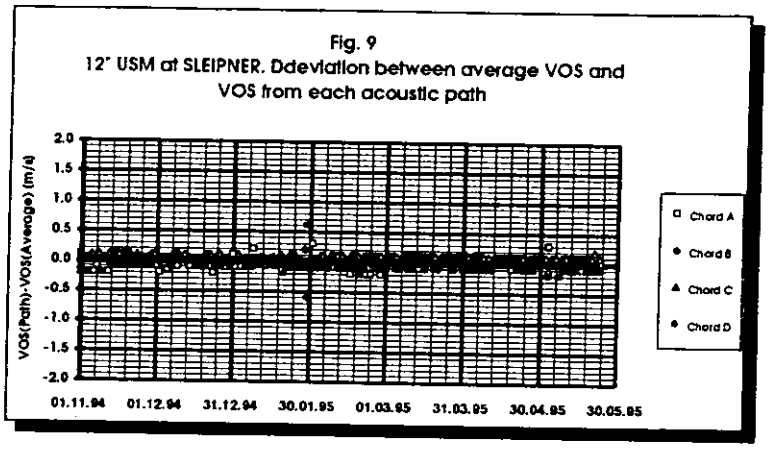


Fig. 9
12" USM at SLEIPNER. Ddeviation between average VOS and VOS from each acoustic path
VOS(Path)-VOS(Average) (m/s)
2.0
1.5
1.0
0.5
0.0
-0.5
-1.0
-1.5
-2.0
01.11.94
01.12.94
31.12.94
30.01.95
01.03.95
31.03.95
30.04.95
30.05.95
Chord A
Chord B
Chord C
Chord D

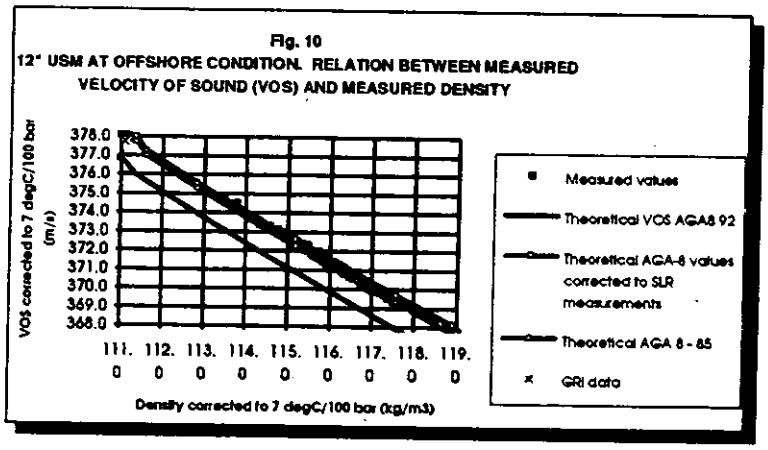


Fig. 10
12" USM AT OFFSHORE CONDITION. RELATION BETWEEN MEASURED VELOCITY OF SOUND (VOS) AND MEASURED DENSITY
VOS corrected to 7 degC/100 bar (m/s)
378.0
377.0
376.0
375.0
374.0
373.0
372.0
371.0
370.0
369.0
368.0
111.0
112.0
113.0
114.0
115.0
116.0
117.0
118.0
119.0
Density corrected to 7 degC/100 bar (kg/m3)
Measured values
Theoretical VOS AGA8 92
Theoretical AGA-8 values corrected to SLR measurements
Theoretical AGA 8 - 85
GRI data

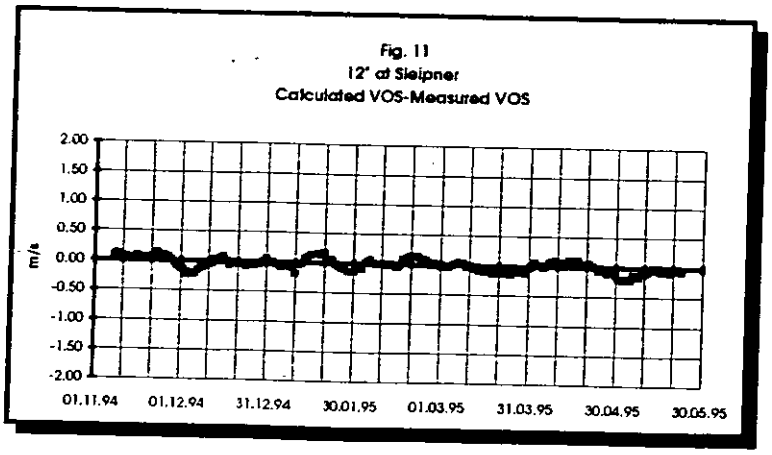


Fig. 11
12" at Sleipner
Calculated VOS-Measured VOS
m/s
2.00
1.50
1.00
0.50
0.00
-0.50
-1.00
-1.50
-2.00
01.11.94
01.12.94
31.12.94
30.01.95
01.03.95
31.03.95
30.04.95
30.05.95

Main Index

North Sea FLOW Measurement Workshop 1995

Paper 6:

CALIBRATION OF GAS CHROMATOGRAPHS FOR IMPROVED PERFORMANCE

1·6

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Calibration of Gas Chromatographs for Improved Performance

By
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Introduction

The Central Area Transmission System (CATS) is a natural gas gathering system located in the U.K. sector of the North Sea. The system is operated by Amoco (U.K.) Exploration Company on behalf of the CATS management group, which besides Amoco includes British Gas, Amerada, Phillips, Fina and Agip. The pipeline is designed to transport 1,600 million standard cubic feet a day of gas through 250 miles (400 km) of 36" diameter pipe. The system pressure varies from 170 bar offshore to the Teesside onshore terminal delivery pressure of 100 bar. The elevated system pressure allows CATS pipeline to accept "rich" natural gas with up to 0.5% Hexanes and heavier hydrocarbons. The gas is delivered to the onshore terminal at Teeside in the dense phase, above the cricondenbar, without the formation of retrograde condensation.

All CATS fiscal measurement for delivery and allocation is based on a component mass-energy using concentric orifice meters (in accordance with ISO 5167), dual on-line gas chromatography and gas density continuously computed using the American Gas Association Report Number 8 (AGA 8) Detail Characterization Method Equation of State. Energy determination is in accordance with ISO 6976 Natural Gas - Calculation of calorific value, density and relative density.

Economic Impact

The economic impact of gas analyses when used to calculate the component mass-energy for commercial purposes is well documented and generally understood within the gas industry. It will suffice to say that the chromatographic analyses yield data that represents more than 50% of the information needed for a total energy calculation. The CATS customary unit for natural gas custody transfer:

Σ (Component tonnes x Gigajoule/tonne) = Total Gigajoules

Principles Of Gas Chromatograph Operation

The elementary principles of the gas chromatograph (GC) are relatively unsophisticated and have been known for many years. The principle is that an individual component will cause a unique response in one of several types of detectors when its presence is sensed. The problem is to separate the individual components in a mixture of natural gas into specific definable component. The evolution of separation media and techniques and detection hardware and methods have resulted in the commercial success of the GC.

Today's GC employs a high purity inert gas which is continually flowed through the instrument. The inert gas most commonly used is helium, but hydrogen or argon can be used when the gas sample contains helium. This gas is referred to as the carrier gas. The carrier gas pressure is carefully regulated. the reduced pressure carrier gas is then filtered to remove moisture. To achieve accurate measurement of the component concentration, an extremely pure carrier gas is mandatory. The recommended carrier gas is an analytical grade or GC grade which is 99.999 percent pure.

The carrier gas is normally flowed through a multi-port sample injection valve before it enters the GC at the heated sample injector. The sample injector valve will be discussed along with the sample injection procedure. The heated sample injector is connected to the chromatograph column (or group of columns) which is used to separate the components in the mixture One way the injector can be used is to inject a sample using a syringe. Syringes are available that can inject a high vapor pressure sample or a liquid. The syringe is inserted into the injector through an external end piece known as the septum.
Required separation is accomplished with one or more columns. Traditional columns are generally made of one-sixteenth to three-sixteenth inch diameter stainless steel tubing. Initially, the tubing is thoroughly cleaned. The column is next packed as tightly as possible with a material that will separate a mixture into individual components. The columns may contain a variety of materials depending on what component separations are required. Column packing generally falls into two groups: "gas-solid" and "gas-liquid". The "gas-solid" column separates the components in the gas using only the surface material and/or the pore structure for the separation. The "gas-liquid" column uses a stationary liquid phase supported by diatomaceous earth, such as Chromosorb P. The newest type of widely used columns utilize capillary tubing normally made of glass. The inside surface of the capillary tubing is coated with a separating media to cause the separation. The capillary tubing is typically 40 to 100 meters long in a laboratory GC. A typical packed column used in a laboratory GC does not exceed 10 meters. The packed columns can not totally separate components heavier than normal pentane. Instead several components are grouped together in the heavier hydrocarbon peaks. The advantage of the capillary column is that heavier hydrocarbon components can be separated allowing cost effective analysis of products as heavy as C_{12}. Hydrocarbons heavier than C_{12} can be accurately analyzed but the time required makes routine gas analysis impractical. The scope of this paper does not allow full discussion of all of the column packing and capillary coating materials; but, sufficient to say, each material used has advantages and disadvantages for various types of separations. Traditional on stream GCs use packed column technology.

GC's are configured with one or more types of detectors to accomplish accurate analyses. The two most commonly chosen detectors are the thermal conductivity and the flame ionization detectors. Seivers, electron capture, and flame photometric are examples of detectors occasionally installed for specific applications. The most specific detector employed is the mass spectrometer. This relatively expensive detector is used to identify

the elution order of the various components in a gas mixture containing a variety of heavier hydrocarbon components. The thermal conductive detector (TCD) is a special resistor that responds to specific compounds based on thermal conductivity with a linearity of 10^4. The flame ionization detector (FID) uses the principle that the electrical conductivity of a gas is directly proportional to the concentration of charged particles within the gas. The effluent gas from the column is channeled through an electrode gap and the organic impurities are ionized by a hydrogen flame. The charged particles within the electrode gap allows a current to flow through the gas and a measuring resistor. The voltage drop is recorded and integrated. The major advantage of this detector is its high sensitivity to organic compounds, greater than 10^6. The disadvantage is the detector gives little or no response to the following components:

He	Ar	$SiHCl_3$	Ne
Xe	O_2	N_2	CS_2
COS	SiF_4	H_2S	SO_2
N_2O	NO_2	NH_3	CO
CO_2	H_2O	$SiCl_4$	

On stream GCs normally use TCD technology. The two commonly used systems are filament or hot wire and thermister. The hot wire is a thin section of wire installed in the detector. The hot wire is operated in a carrier gas atmosphere. The carrier gas serves two purposes: provide a base thermoconductivity so that an expected detector response can be determined for use as a base line and to cool the filament. Without carrier gas flow the powered filament will be damaged. The thermister is more rugged and less susceptible to damage when the carrier gas runs out. Two carrier gas cylinders with an automatic switch over feature are recommended. The operator must monitor the carrier gas pressure so that carrier gas replacement is done on a timely basis.

The gas sample is injected into the carrier gas using a gas injection valve. The sample injection valve is normally equipped with an external sample loop. The sample loop ranges in size from approximately 0.25 to 2.00 cc. The smallest sample loop that can produce acceptable results should be used. This will result in the development of maximum linearity for each component analyzed and as well as being able to repeatably detect all of the components in the mixture. The sample injection valve is a four, six, eight or ten port valve that allows the uncontaminated carrier gas to flow through using two ports while the valve is in the normal position. Sample gas is delivered to the sample loop connected to two ports adjacent to the carrier gas ports that can be connected to the flowing carrier gas by rotating the valve. For the most repeatable results, the sample loop is evacuated and then filled with the gas sample to zero gauge. An alternate method used by most on stream GC manufacturers is to purge the sample loop and reduce the sample loop pressure to near zero before the gas sample is injected. It may be necessary to insulate and heat trace the sample injection valve and the connecting tubing to the injector.

GC Calibration Standard

The standards must be heated to 60° C for an adequate period of time to assure that all of the heavier components are forced into the gaseous phase and adequate mixing has occurred. A 5° C differential temperature between the bottom and top of the sample cylinder is sufficient to mix the sample. For optimum performance, the standard sample cylinders should be heated all of the time which allows use whenever desired. The standard gas samples should also be blended to produce the desired heating value and relative density as well as the required compositional analyses. Natural gas standards should be replaced when the pressure falls below 3-4 barg or 50 percent of the pressure achieved after blending is depleted, whichever is lower, or when the standard is one year old. If there are significant gas composition fluctuations in the flowing stream causing the relative density changes greater than +/- 2%, due to economic reasons, variations in cold plant operations or changes in producing zones or wells, two or more calibration standards may be required.

An excellent check of the standard is accomplished by sending the standards to a responsible third party laboratory that can perform an extended analysis. If the standard vendors analysis and the third party laboratory analysis agree within the tolerances expected, the standard is deemed satisfactory. The acceptable GC tolerances for the various components have been reduced commensurate with Amoco's extensive test matrix.

Composition	Repeatability	Reproducibility
N_2	2.0 %	4.0 %
CO_2	2.0 %	4.0 %
C_1	0.2 %	0.7 %
C_2	1.0 %	2.0 %
C_3	1.0 %	2.0 %
IC_4	2.0 %	4.0 %
NC_4	2.0 %	4.0 %
IC_5	2.0 %	4.0 %
NC_5	2.0 %	4.0 %
C_6 GROUP	5.0 %	10.0 %
C_7+	5.0 %	10.0 %

CATS Operator procedures involve sending the new calibration gas standard to the designated third party laboratory (used for monthly composite sample extended analysis for C6+ or C7+ characterization) to cross correlate and verify the sample and the lab simultaneously. If agreement is not achieved per the table above, the sample should be returned to the vendor for replacement or the lab methods and procedures should be verified. Another method of quickly verifying that a new standard is satisfactory is to acquire and test the new standard on your GC as an unknown gas before the existing standard is depleted below a satisfactory pressure or becomes too old.

The separation of the gas mixture is accomplished using the column(s) carrier gas flow rate and oven temperature. The flow rate of the carrier gas ranges between 20 and 60 cc per minute; but, the flow rate usually is about 30 cc per minute. The flow rate should be verified and logged at least daily and when peak elution times begin to drift. The operating pressure is approximately 8.5 barg. The carrier gas cylinder pressure should be checked often and the GC should be automatically powered down if the preset carrier gas pressure can not be maintained. Additional security is obtained when several carrier gas cylinders are connected to the supply system using commercially available mullet cylinder connection equipment.

The column oven temperature is normally operated in one of two modes to aid in component separation:

- isothermal
- temperature programmed

A GC can produce accurate results in either mode but, the efficiency of the heavier hydrocarbon component separation is more limited when operating isothermally. If good lighter component separation is obtained, the heavier peaks may become very broad with a low amplitude which does not contribute to repeatable results. A two plateau temperature program and the proper temperature ramping rate can produce much improved results. A typical temperature program is shown below for illustration purposes; but, each new column(s) installed will exhibit a different efficiency based on liquid phase coating, support media size, and how tight the column was packed.

The temperature program for a DC 200/500 stationary liquid phase on a 80/100 mesh Chromosorb P acid washed base is detailed below. This is the most common single column used to separate hydrocarbons through C_5's along with N_2 and CO_2.

	Column Temperature	**Duration**	**Program Rate**
Initial Temperature	70 ° C	2 Minutes	
Ramping Rate			32 ° C per Minute
Final Temperature	180 ° C	9 Minutes	

The detector temperature should be set higher than the maximum oven temperature based on the manufacturers recommendation, usually 25 to 50° C. The injector zone temperature, the oven temperature, and the detector zone temperature should be monitored and logged daily. A failure in the temperature control system will cause inaccurate measurement.

Most on stream GC's operate isothermally and most laboratory GC's can be temperature programmed. Laboratories have been checked that could use temperature programming;

but, choose to continue to test isothermally. Both efficiency and accuracy may be improved with temperature programming.

ISO 6569 Natural Gas - Rapid Analysis by Gas Chromatograph and/or GPA Standard 2261, Analysis of Natural Gas and Similar Gaseous Mixtures by Gas Chromatography should be followed to achieve the best results.

Sampling for On-line Analysis

Samples points for on stream gas chromatographs require special attention to assure proper performance. A sample heating method is required at or before the point that the sample pressure is reduced for the GC. The sample line must also be completely heat traced and insulated up to the point that it enters the GC to avoid heavy hydrocarbon liquid drop out. The temperature maintained in the sample line must be a minimum of 11 to 28 °C above the flowing pipeline temperature to assure the hydrocarbon dew point is never reached. Ideally, the sample line will have a continuous slope from the sample source to the end device so that any free liquid will drain back into the pipeline. Realistically, other equipment and the design of the building may force the sample line to be routed differently. In this case, a free liquid trap should be installed at all low points to allow to assure the GC will operate properly.

Sample Cylinder Preparation

The first item needed to obtain an adequate sample is a clean sample cylinder with both valves in good repair. The valves should be checked using either/or both high pressure and vacuum to assure no leakage is present. The choice of how to test the sample valves depends totally on how the sample cylinder will be used to obtain the sample. A high pressure check is done by immersing the pressurized cylinder and both valves in water. A vacuum pressure test is accomplished by observing a vacuum test gauge or manometer for approximately ten minutes. For a piston cylinder, both sides of the piston should be pressurized for the water test. Standard cylinders should be cleaned using steam to assure they are properly prepared. The proper use of steam cleaning will assure that the heavy hydrocarbons are removed from the sample cylinder. Piston cylinders should be cleaned in accordance with the manufacturers recommendations for the removal of heavy hydrocarbons. All cylinders should be dried using dehydrated air or an inert gas that is free of water. Finally the cylinder is evacuated using a vacuum pump. Cylinders lined with materials like Teflon have been used in a effort to control the loss of H_2S and other reactive compounds.

Specification of Composition for the Calibration Gas Standard

Based on years of experience in chromatography, Amoco/CATS recommends for optimal chromatograph performance, the composition of the gas used for periodic calibration of the GC (cal gas) should include all naturally occurring hydrocarbons in sufficient quantity for adequate peak resolution. An example of the proper calibration gas is described as follows:

COMPONENT	COMPOSITION
2-Methylpentane	0.20 %
2,2-Dimethylbutane	0.05 %
Cyclohexane	0.05 %
N-Heptane	0.30 %
N-Hexane	0.20 %
N- Pentane	0.35 %
Isopentane	0.35 %
Neopentane	0.10 %
N-Butane	1.00 %
Iso-Butane	0.50 %
Propane	3.00 %
Ethane	7.00 %
Carbon Dioxide	2.00 %
Nitrogen	1.50 %
Methane	Balance

Calibration standards should be a gravimetric mixture produced using weights traceable to N.P.L. standards. The certificate of composition data should include the chemist's name, date certified, cylinder size, cylinder serial number, valve type and the actual composition.

This standard composition is a departure from other schools of thought that suggest the use of a similar (to the flowing stream) gas composition. Apparently, for economic reasons some advocates recommend using a spot sample of the actual gas stream (analyzed at a 3rd party laboratory) as the calibration gas standard. Amoco strongly disagrees with this approach for two primary reasons; it does not insure detector linearity over a normal range of variations in gas composition and it adds another step in the laboratory tracability.

The initial Teesside sales gas GC standard was the vendor's recommended, lean standard which did not require additional heat due to it's lower hydrocarbon dew point. After start up and commissioning of the system, a new, heated (60 C) standard with the above composition was installed and both GCs immediately produced a step change in Relative Density of + **0.6 %** (approximate change in mass of 0.3%) !

Chromatograph Performance Verification

CATS Operator is required to conduct natural gas chromatograph performance verifications (audits) to assure that laboratory and on stream instruments provide accurate gas analyses for the calculation of calorific value, density and relative density. The procedure guarantees commercial exchanges are made on an equitable basis. Practically speaking many factors affect detector performance requiring two or more samples covering the range of the unknown gases to be analyzed to assure adequate detector performance. A family of highly accurate gas standards is mandatory before any gas chromatograph can be confidently verified. These standards must contain the components that will be present in the unknown sample. If the detectors used in the gas chromatograph were totally linear, verification and calibration could be accomplished with a single, lean natural gas standard. Extrapolating the response factors for the heavy hydrocarbon gases from the experimentally determined response factors for the lighter hydrocarbon factors is extremely dangerous. Naturally occurring heavy hydrocarbons with the same number of carbon atoms do not all have the same thermoconductivity factors. When extrapolated response factors are used, the amount of error introduced in compressibility, relative density, and heating value calculations varies with the amount of heavy hydrocarbons present.

This verification procedure utilizes natural gas samples that represent the range of components that would be normally found in CATS transported natural gas. Once properly heated, the samples are analyzed by each gas chromatograph at the facility. The resulting mole percentages are compared for accuracy, and each chromatograph's relative response factors for normal compounds are used for a plot to check the chromatograph's detector linearity. The test procedures and a critical review of practices and procedures can determine the ability of a chromatograph to provide analyses and resulting calorific value calculations that are repeatable within +/- 0.25 %.

The response factors developed for each standard are used to check the performance of the GC. A procedure for plotting the log of the molecular weight of the each normal component versus the log of the relative response factor of that component is detailed in GPA Standard 2177, Tentative Method for the Analysis of Demethanized Hydrocarbon Liquid Mixtures Containing Nitrogen and Carbon Dioxide by Gas Chromatography. Propane has been chosen as the compound to which all of the other compounds are related. The resulting curve is normally referred to as a "Relative Response Factor (RRF) Plot". If the resultant plot is a straight line, the detector is operating in the linear range.

Calibration Results

Using the recommended calibration gas composition described herein, the two Teeside chromatographs have been calibrated on a weekly basis. Performance evaluations using the above described method (Log - Log plot of RRF vs Mol. Wt.) are provided in Figures 1-24. Each graph includes two runs each from both machines, or in other words each plot

represents four lines that essentially line on a single path. In addition to near perfect detector linearity, these results support Amoco's reasons for using a rich cal gas by establishing exceptional variability between the two machines as the difference in computed Molecular Weight is typically less than 0.02 %.

A statistical evaluation (standard deviation and 95% confidence values) of the average Relative Response Factors from these calibrations is shown below:

Teeside GC Analyzer Number 1

Composition	Avg. RRF	Std. Deviation	95 % Confidence
Methane	2.035515	0.010406	0.004163
Nitrogen	1.695678	0.019662	0.007866
Ethane	1.271405	0.004171	0.001669
Neo-Pentane	0.804509	0.003452	0.001381
Carbon Dioxide	1.397482	0.006560	0.002624
Propane	1.000000	0.000000	0.000000
Iso-Butane	0.846650	0.001466	0.000587
Normal Butane	0.826140	0.001834	0.000743
Iso-Pentane	0.733816	0.004412	0.001765
Normal Pentane	0.713262	0.005790	0.002316
Hexane Group	0.648190	0.011149	0.004461
Heptanes Plus	0.525399	0.013029	0.005212

Teeside GC Analyzer Number 2

Composition	Avg. RRF	Std. Deviation	95 % Confidence
Methane	2.008504	0.008850	0.003617
Nitrogen	1.660023	0.018327	0.007490
Ethane	1.263057	0.004235	0.001731
Neo-Pentane	0.768648	0.146725	0.059963
Carbon Dioxide	1.380554	0.005987	0.002447
Propane	1.000000	0.000000	0.000000
Iso-Butane	0.844928	0.001391	0.000568
Normal Butane	0.826427	0.001563	0.000639
Iso-Pentane	0.737460	0.003470	0.001418
Normal Pentane	0.716241	0.004470	0.001827
Hexane Group	0.649519	0.009219	0.003768
Heptanes Plus	0.519532	0.014650	0.005987

Worldwide GC Survey Results

Initial Survey Results

Within the last three years, thirty-six locations have been evaluated by using the previously outlined method. Nine of those locations have been revisited since the initial survey. A copy of the survey form is attached. It should be noted that only six of the initial thirty-six laboratories surveyed were determined to have no discrepancies. Nine of the laboratories were left with no discrepancies as a result of the cooperative efforts of the Amoco survey team and personnel of the companies being surveyed. This cooperation resulted in "point forward" accurate analyses. The discrepancies reported were placed into seven categories. These are:

- Not heating field samples
- Non linear response factors
- Calibration gas not properly heated
- Calibration standard out of date
- Primary calibration gas not used
- Integration, calculation or recognition of peaks
- Calibration standard not representative

The discrepancy that occurred most frequently was "calibration gas not being heated". "Primary calibration gas not used " only occurred once.

Follow-up (Return) Results

Of primary interest is the additional category, "Other". This category was added to reflect the new discrepancies that were noted at the return visit but were not noted during the initial survey. Two of the eight labs revisited were found to have corrected all initial discrepancies. The highest occurring discrepancy was once again, "calibration gas not properly heated", although this number was reduced from the initial occurrences.

Conclusions

The use of a proper composition calibration standard, heated to insure there is no separation due to gravity segregation is economical and necessary for accurate gas measurement on an energy basis.

Properly designed and calibrated gas chromatographs demonstrate optimal detector linearity with minimal variability between machines.

The survey method describe herein has been extensively used over the last two years to evaluate laboratory and "on-line" gas chromatograph performance in the United States, the United Kingdom, Norway and Trinidad. More than twenty million dollars in lost revenue have been identified as a result of these tests.

The major benefits of this approach to GC performance evaluation include:

- Immediate trouble shooting and evaluation of performance
- Immediate elimination of errors on a "point forward" basis in many cases
- Elimination of return trips for follow up testing
- Partnering with other companies to achieve a common quality assurance
- Continuity

In the future, only the companies that assure accurate measurement in an efficient manner will survive.

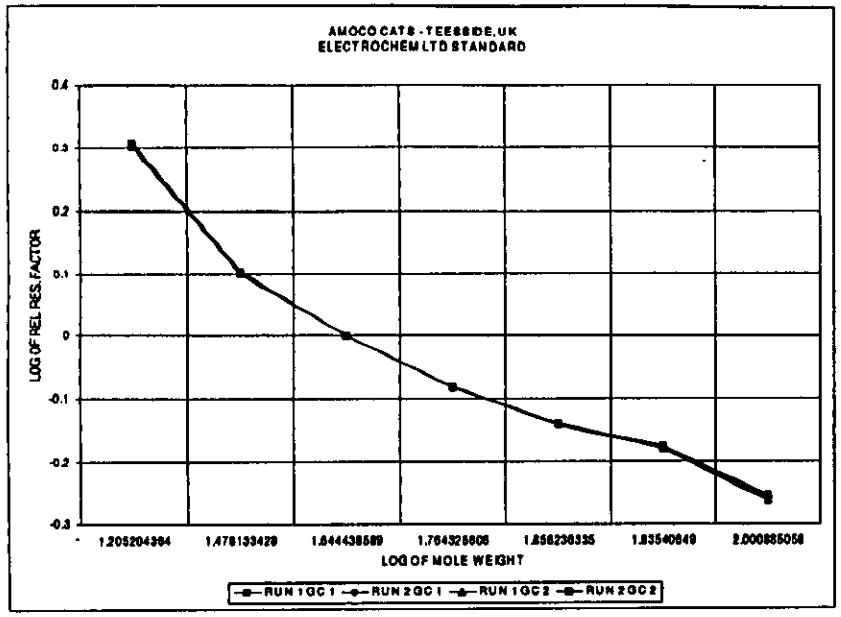


Figure 1

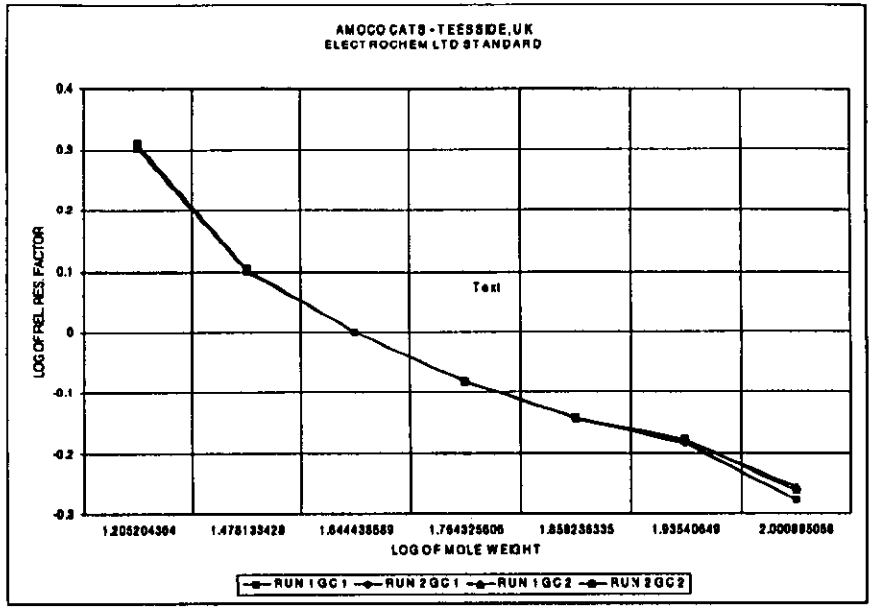


Figure 2

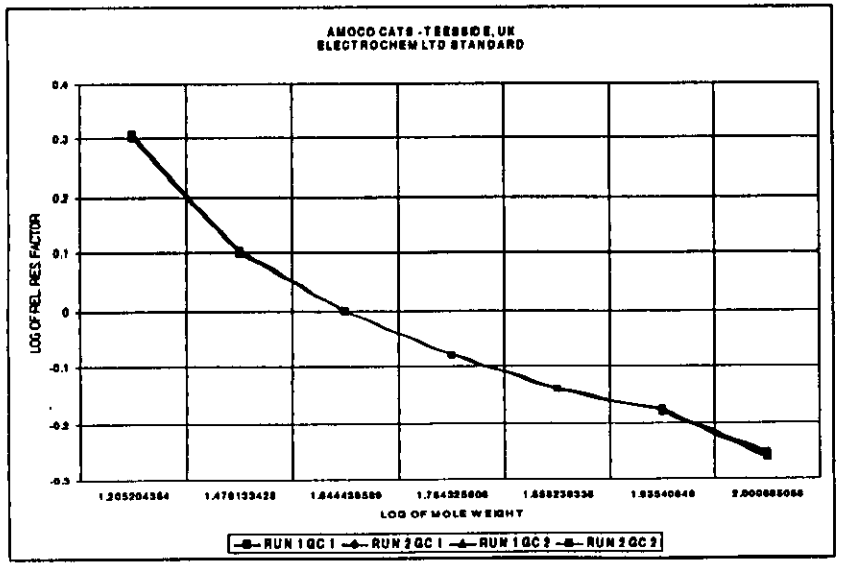


Figure 3

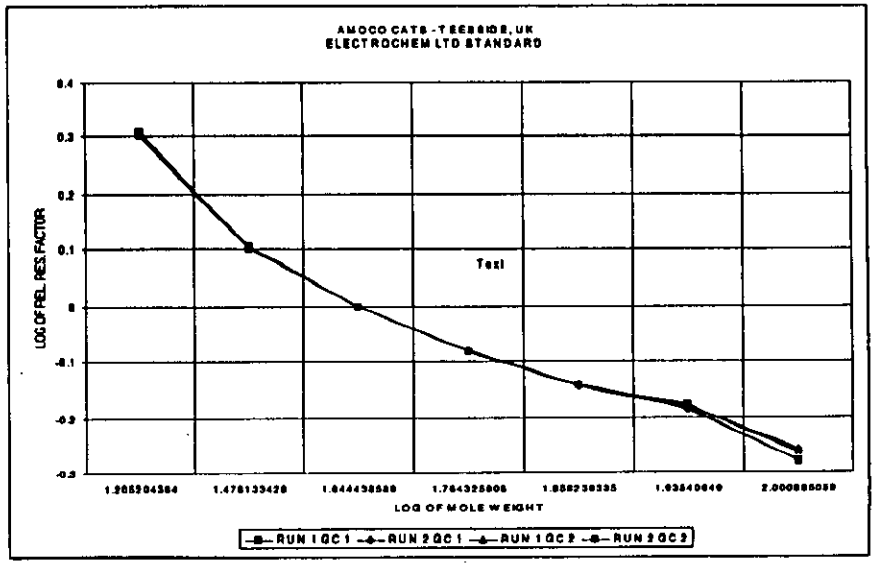


Figure 4

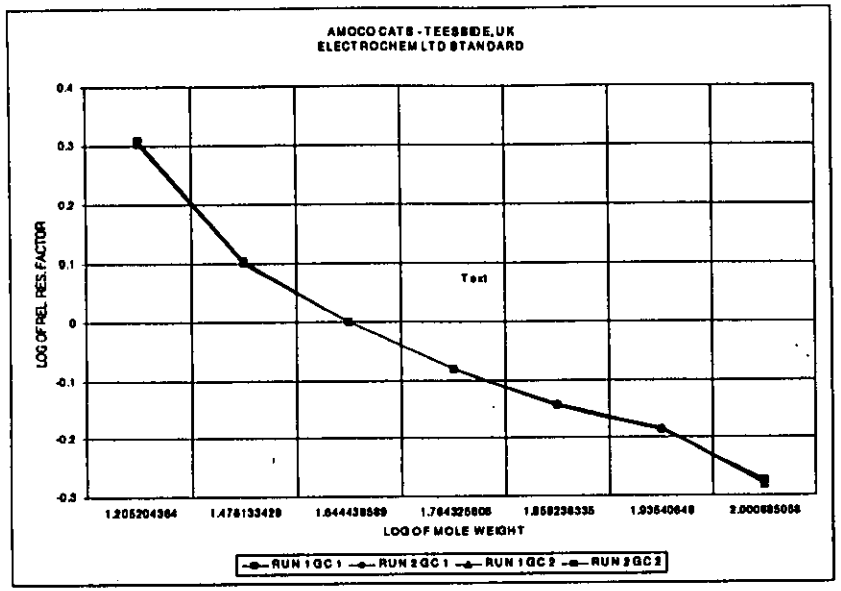
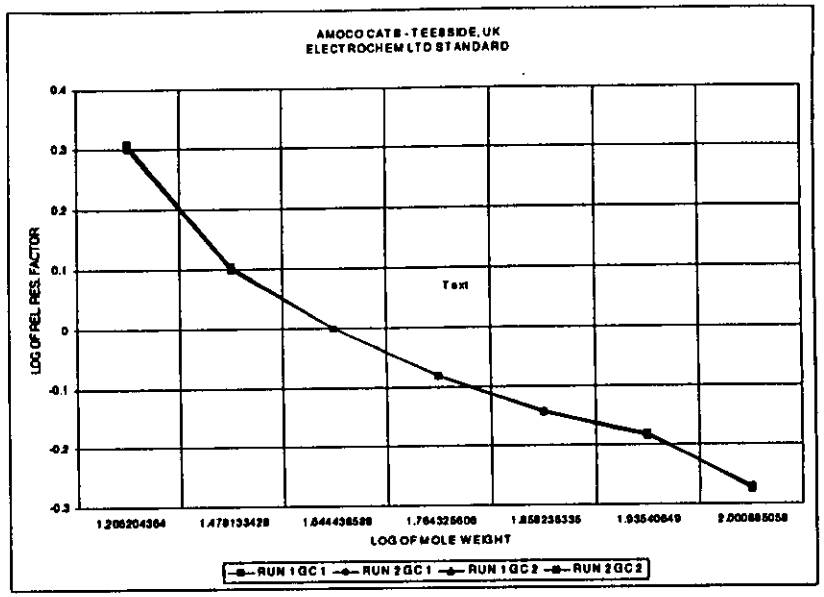


Figure 5



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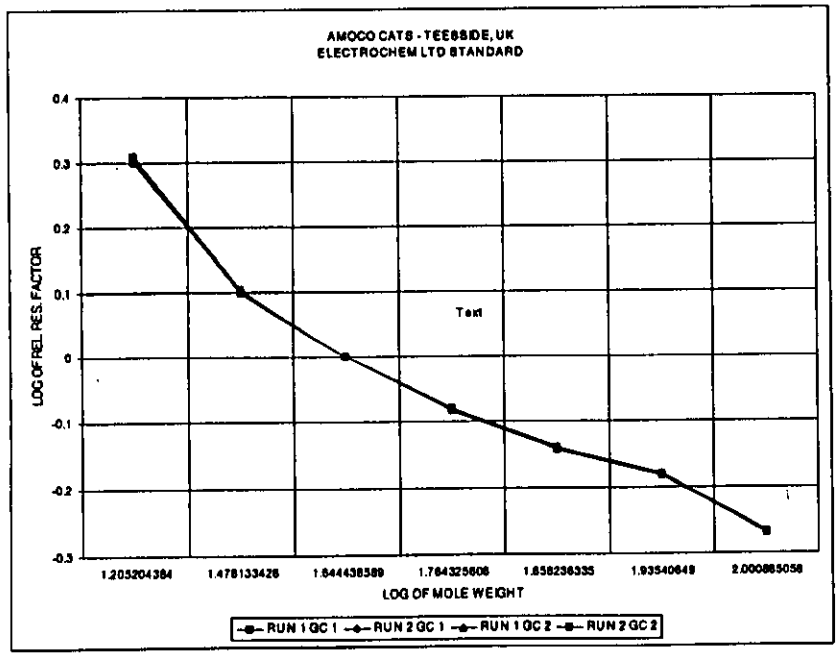

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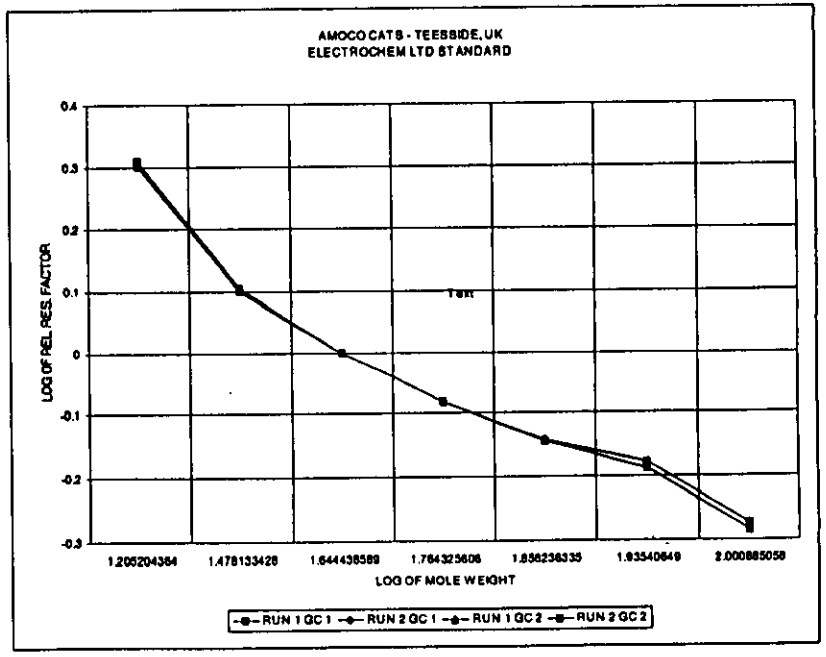

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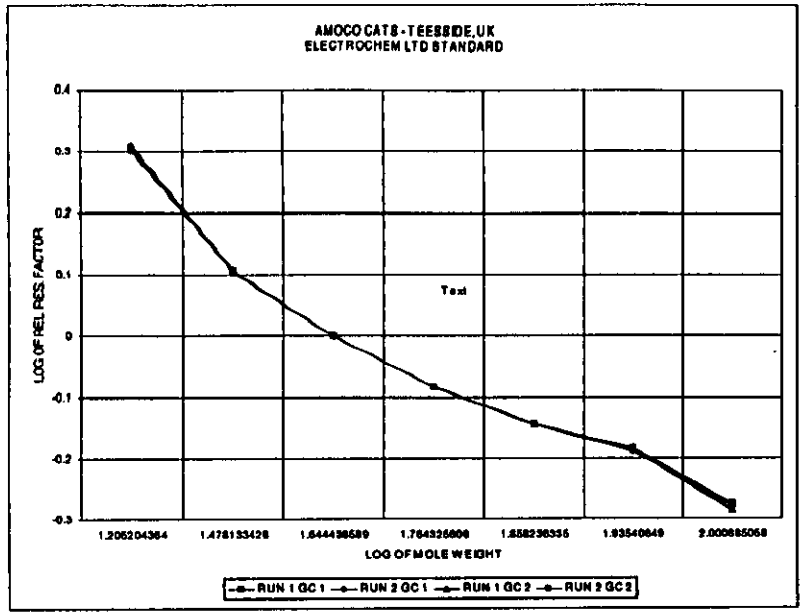

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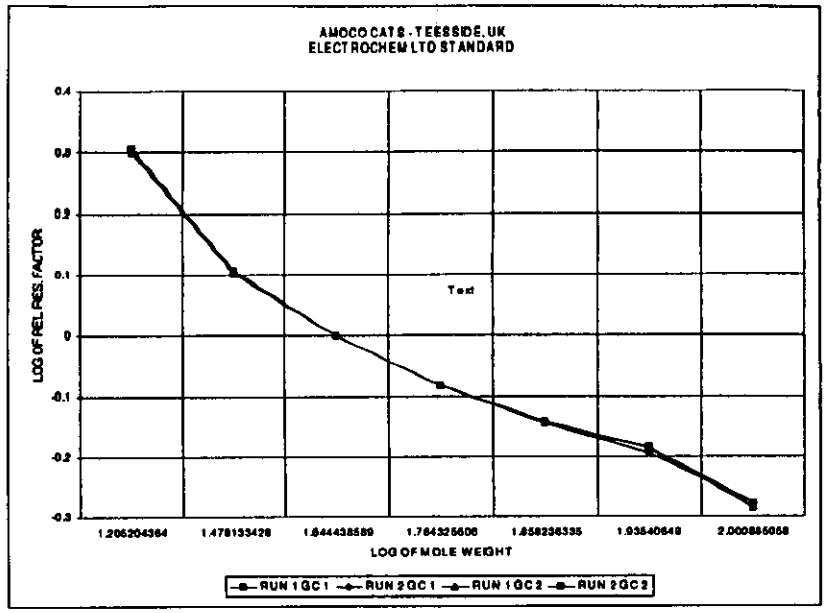

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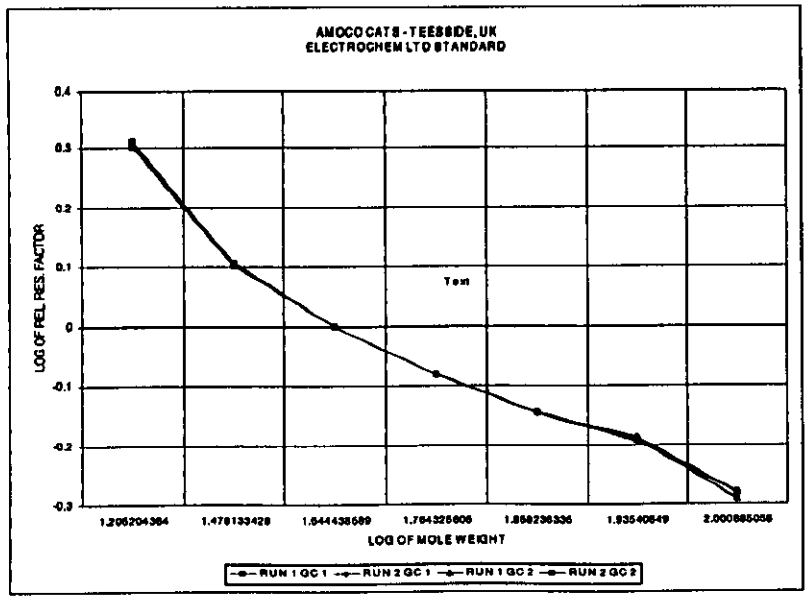

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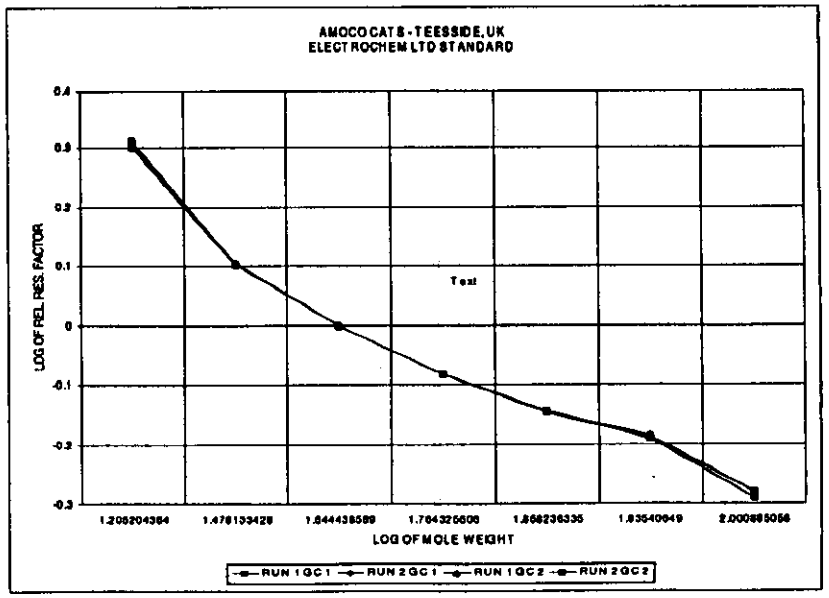


Figure 12

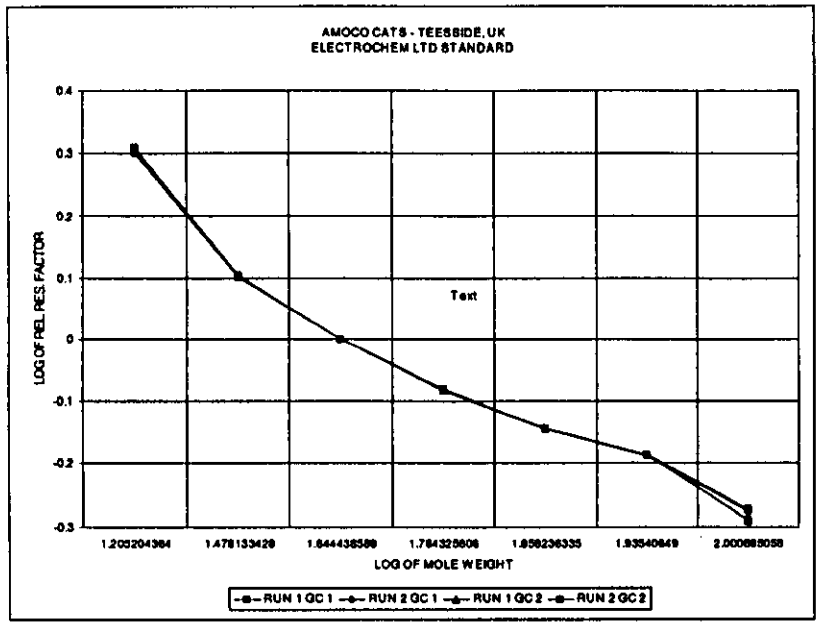
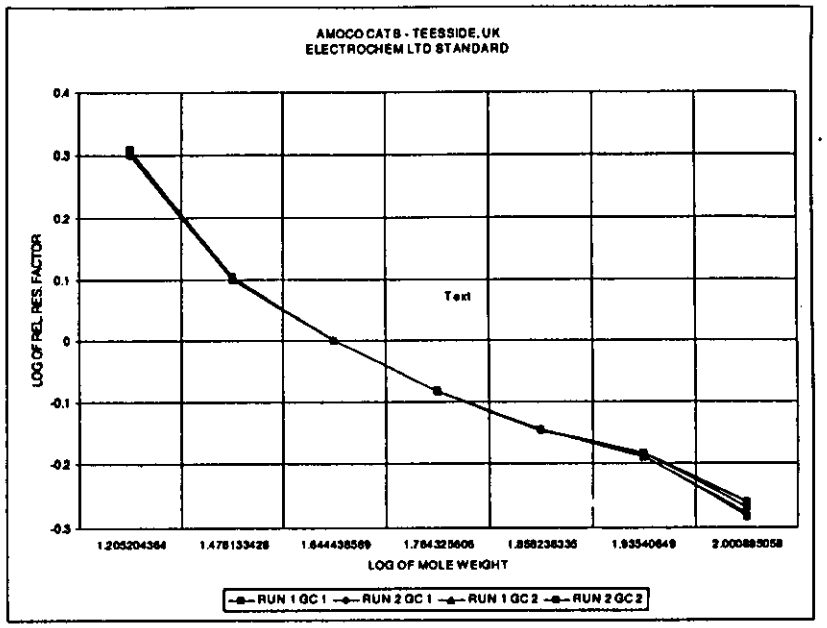


Figure 13



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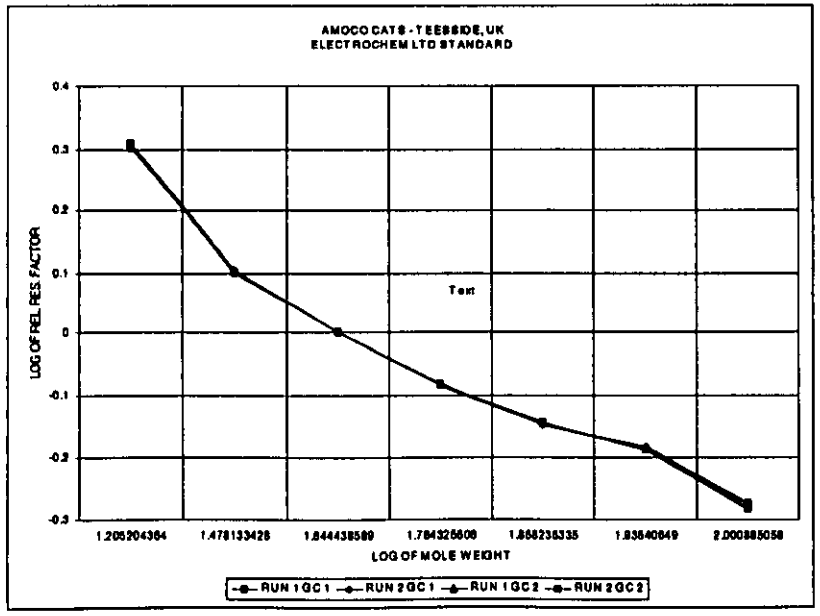

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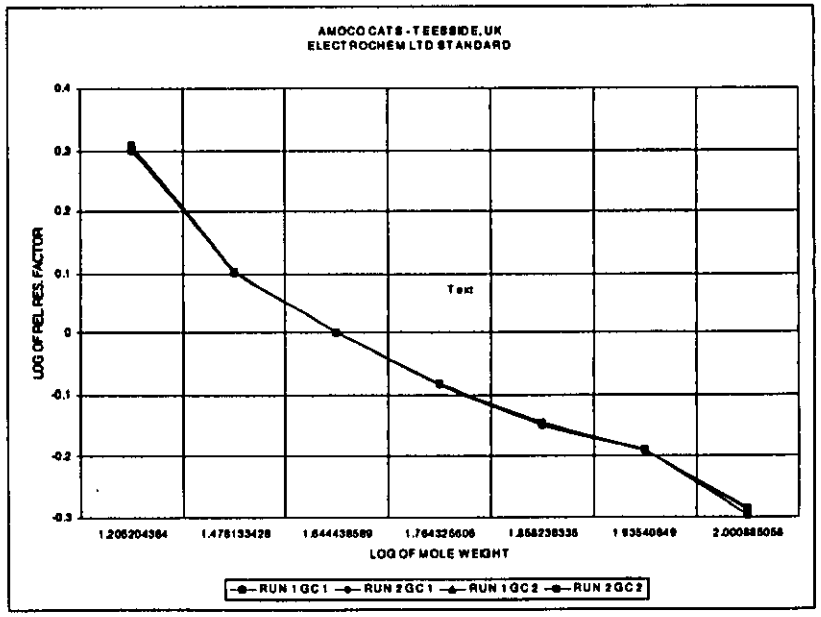

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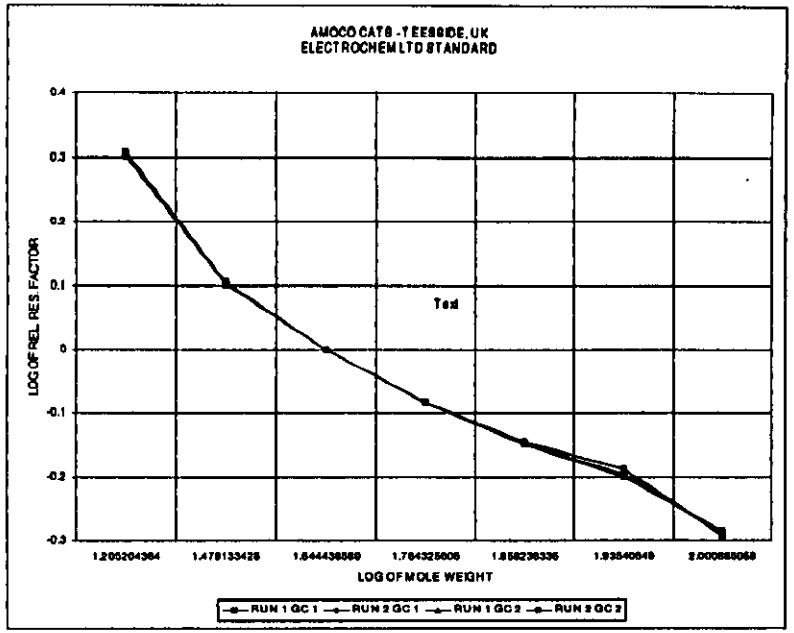
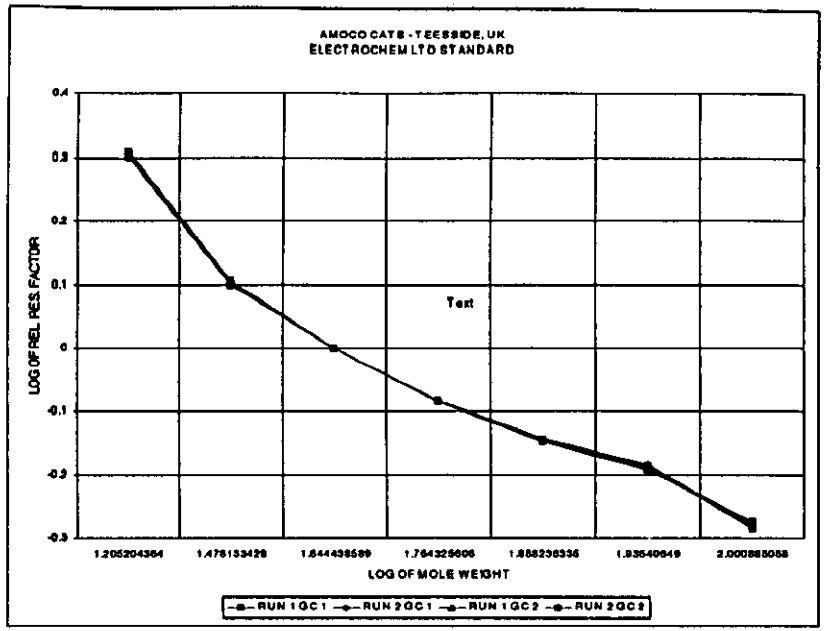


Figure 17



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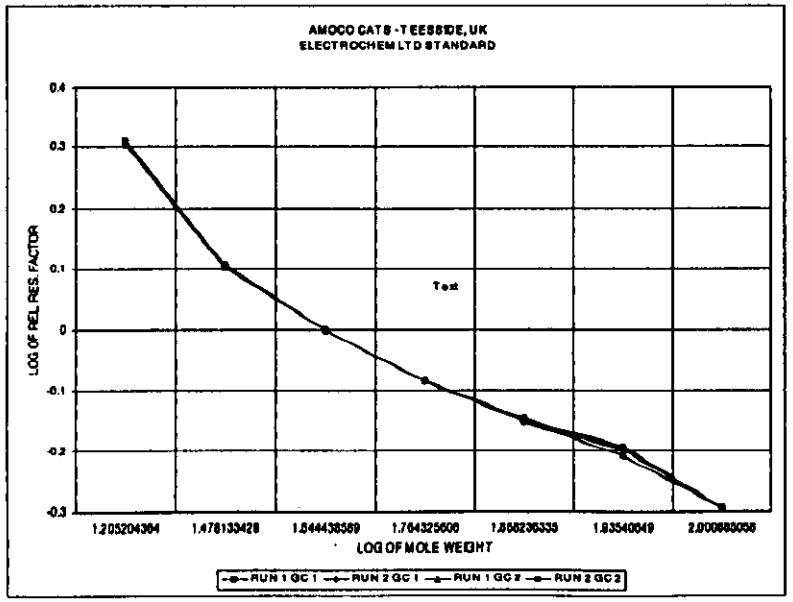

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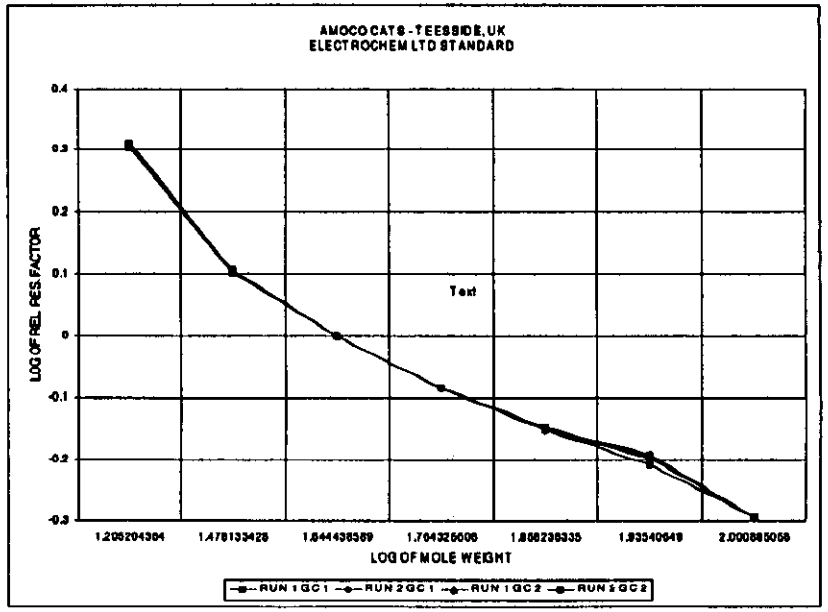
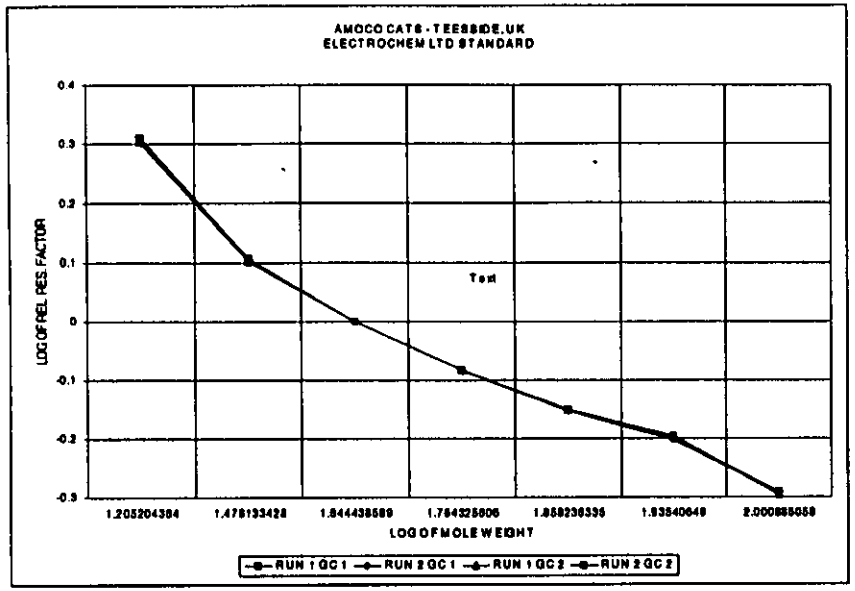


Figure 20



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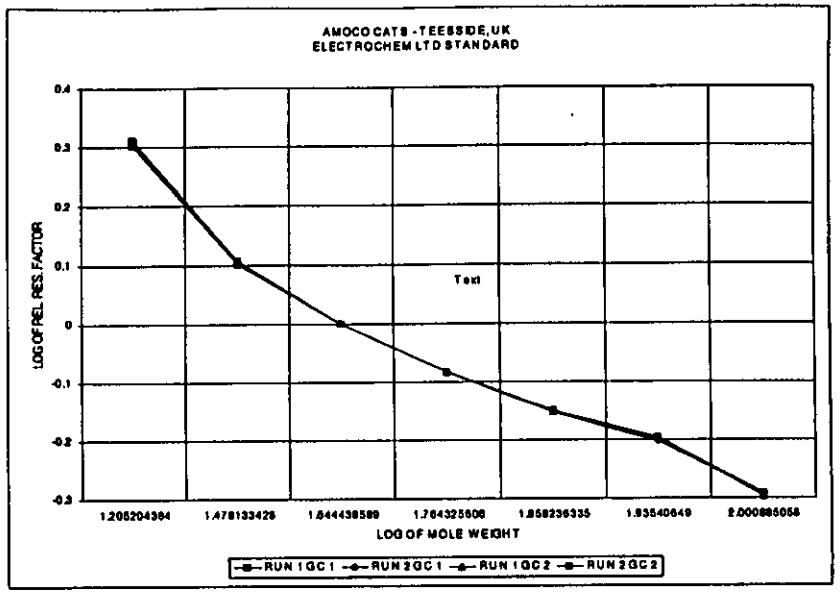

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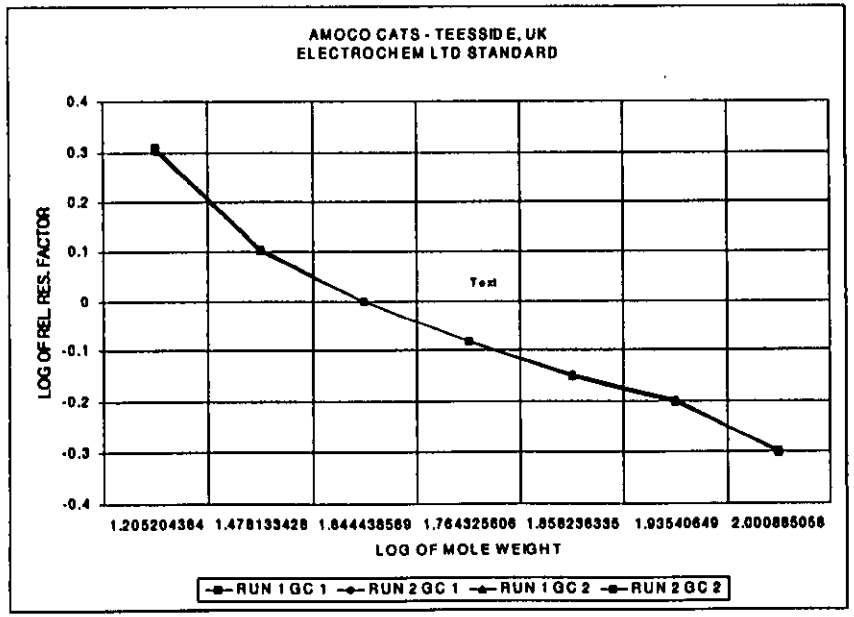

Figure 23

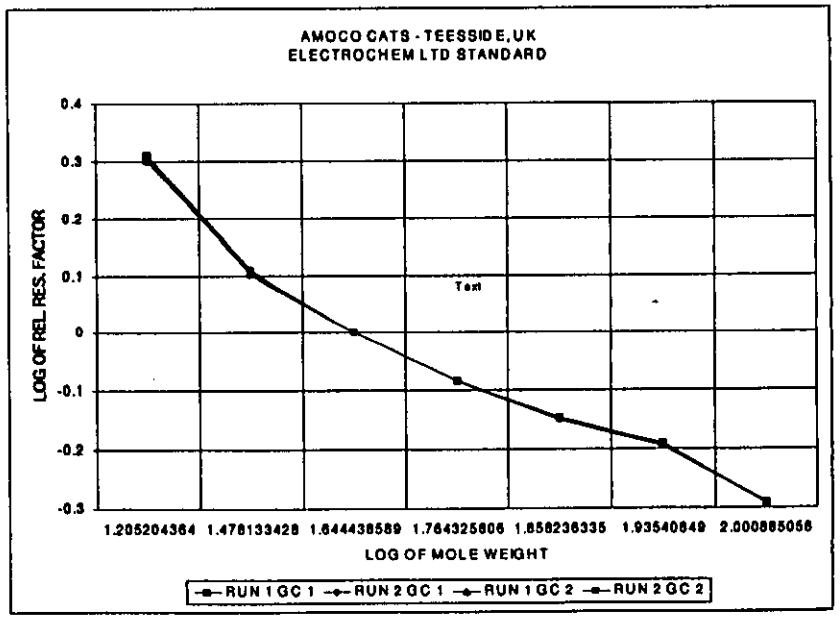

Figure 24

PROVIDE THE FOLLOWING EQUIPMENT DETAIL FOR EACH ANALYZER TO BE USED:

: **Analyzer**

Make _____

Model _____

Column Configuration

_____

(Column and Description)

_____

_____

_____

_____

Type of Detectors _____

Integrator

Make _____

Model _____

Last Component Analyzed

(i.e. C_5, C_6, C_6+) _____

TEAM CHECK LIST

1. **Sample Handling & Conditioning**

	Yes	No
Samples Heated	___	___
Temperature Monitored	___	___
Temperature at 140 °F (+/- 5 °F)	___	___
Time of sample heating monitored	___	___
Duration of heating in hours	_____	
NOTE: Normal heating time is 24 hr (± 12 hr)		
Analyzer room heated	___	___
Analyzer room Air-conditioned	___	___
Sample taken immediately from heater to analyzer if manually transferred	___	___
Are connections, lines & hardware between sample Cylinder and Analyzer insulated	___	___
Are connections, lines & hardware between sample Cylinder and Analyzer heated	___	___
Sample loop size is		
0.25 cc	___	___
0.50 cc	___	___
1.00 cc	___	___
Other (Specify size)	_____	
Vacuum injection system	___	___
Purge injection system	___	___
If a purge system is used, is there back pressure	___	___
Is the purge rate read or measured	___	___
Record the purge rate	_____	
Helium carrier gas is used	___	___
Is carrier gas pressure monitored	___	___
Is the carrier gas flow rate monitored	___	___
If yes, record the flow rate in cc/minute	_____	
Carrier gas is 99.999 purity	___	___
If no, record the carrier gas purity used	_____	

2. **Analyzer**

	Yes	No
Is this an isothermal run	___	___
If yes, record Temperature in °C	_____	
NOTE: If no, secure copy of temperature program		
Are the columns configured per GPA 2261	___	___
If no, list the configuration	_____	
Integration method is:		
Peak Height	___	___
Area	___	___
Highest carbon number component analyzed is:		
C6	___	___
C6+	___	___
C7	___	___
C7+	___	___
Other (Specify)	_____	
NOTE: Team secure Chromatogram		
Calibration schedule is		
Daily	___	___
Weekly	___	___
Monthly	___	___
Other (Specify)	_____	
Analysis frequency is:		
Daily	___	___
Weekly	___	___
Monthly	___	___
Other (specify)	_____	

CALIBRATION STANDARD GAS

Manufacturer	_____	
Less than one year old	___	___
If no, list the date blended	_____	
NOTE: Team secure a copy of analysis of the standards normally used.		
Is the standard heated continuously	___	___
If no, list the length of time heated	_____	
Is standard heated to 140 °F (± 5 °F)	___	___
If no, state the temperature in °F	_____	
Is an insulation blanket used	___	___
Is pressure on the standard monitored	___	___
If yes, record the pressure in PSIG	_____	
Is the Dew Pt. provided	_____	
If yes, record Dew Point	_____	
Is sample ever exposed to Temp. below Dew Point	___	___

CALCULATION

	Yes	No
Performed in accordance with the latest 2145 (1994)		___
Performed in accordance with the latest 2172 (1994)		___
Other methods used	___	___
If other, please specify		
Values for C6+ or other heavy Fraction		
C_6	___	___
C_{6+}	___	___
C_7	___	___
C_{7+}	___	___
Other (Specify)		
Composition of Fraction		
C_6	___	___
C_7	___	___
C_{8+}	___	___
Other (Specify)		
Resolution, number of significant figures		
Control Charts used	___	___
Other (State)	_____	
Long term logging of response factors		___

NOTE: Rating by Team

Main Index

North Sea FLOW Measurement Workshop 1995

Paper 7:

FLOATING PRODUCTION AND STORAGE SYSTEMS -MEASUREMENT IN THE NEW ERA

2·1

Authors:
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SGS Redwood Technical Service, UK

Organiser:
Norwegian Society of Chartered Engineers
Norwegian Society for Oil and Gas Measurement
Co-organiser:
National Engineering Laboratory, UK

FLOATING PRODUCTION AND STORAGE SYSTEMS - MEASUREMENT IN THE NEW ERA

by

Dr John Miles
and
Dr Eric Robinson

SGS Redwood Technical Services

SUMMARY

The paper considers the implications for oil measurement posed by the introduction of floating production and storage systems which are becoming increasingly common in the offshore environment.

The requirements of the measurement systems installed on floating storage vessels are described and uncertainty analyses are carried out for various tank gauge based systems. It is shown that provided specific operating procedures are adopted the uncertainties achieved by tank gauging systems can match those of meter systems.

A number of potential improvements are proposed and various practical considerations to ensure optimum measurement performance are highlighted.

1 INTRODUCTION

At the beginning of 1995 there were at least thirty projects, either existing or planned involving the use of floating production or storage systems in the UK sector of the North Sea. These projects differ in detail but broadly they can be categorised into four different types as follows:

a) SWOPS (single well operation/production) type vessel (fig 1)

The vessel is totally self-contained. It connects to a subsea wellhead, performs production, separation and storage functions, disconnects and transports the cargo to the discharge location using its own propulsion system.

b) FPSO (floating production/storage) (fig 2)

Similar to SWOPS but the vessel is permanently connected to the subsea wellhead. The propulsion system is normally limited to positional needs only. The cargo is discharged to a shuttle tanker.

c) FSU (floating storage) (fig 3)

The vessel provides storage facilities only. It may require a propulsion ability for positioning. The cargo is again discharged to a shuttle tanker.

d) Barge or Subsea Tank (fig 4)

The barge is moored to a buoy and provides a storage capability only. Again a shuttle tanker is employed. No subsea tanks are in use in the UK sector at present.

In each of these cases there will be a requirement to measure the crude oil to satisfy fiscal, allocation or custody transfer purposes.

Fiscal measurement requirements can in some cases be satisfied by installing a metering system and sampling equipment on the production platform, but where no suitable fixed installation exists, this option is obviously not available. In this case the solution must almost inevitably be provided on the floating storage unit.

In many installations of this kind the key point of reference for custody transfer is at discharge from the storage vessel.The measurement requirements for custody transfer are somewhat more flexible than those for fiscal purposes in that commercially acceptable compromises can be introduced. For example where the transfer of crude oil to a tanker involves a change of ownership the two parties concerned may agree to base the commercial transaction on the outturn figures of the tanker at discharge. Whilst this compromise may save the seller a significant investment in sophisticated measuring systems on board the storage vessel it obviously means that he is totally dependent on discharge measurements over which he has no control and which he has no means of validating. There is therefore a significant incentive to install suitable measurement equipment and to develop compatible operating procedures on the storage vessel to

satisfy custody transfer needs.

We therefore have a situation where high quality measurement on board the storage vessel may be an essential requirement for fiscal purposes and a very desirable option for custody transfer purposes.

2 MEASUREMENT OPTIONS

In the ideal world crude oil discharges from the storage vessel would be measured by a metering system designed for the purpose. Unfortunately the costs of such equipment are very high and may not be considered justifiable unless fiscal requirements dictate. Furthermore in some situations, operational problems can arise where high viscosity crude oils need to be maintained at a high temperature to suit the operating characteristics of the meters. There is therefore a significant incentive to avoid the use of metering systems and to base the measurements on tank gauges and other shipboard instrumentation. However such an approach will only be feasible for custody transfer purposes if acceptable measurement uncertainties can be achieved, and for fiscal purposes if uncertainties comparable with those achieved by metering are attainable. In practice it has always been argued that measurement by tank instrumentation cannot consistently achieve the levels of uncertainty produced by metering systems, and as a consequence, meters are still required for fiscal measurement. The remainder of this paper examines the use of tank instrumentation as an alternative to metering on storage vessels, comparing the measurement uncertainties and the relevant operational issues involved.

3 COMPARISON OF MEASUREMENT UNCERTAINTIES

3.1 Metering Systems

Uncertainty analyses of metering systems designed to fiscal standards generally produce an overall figure in the range +/-0.2 to 0.25%. Although this is a theoretical figure, experience indicates that similar results are achieved in practice provided the system is operated and maintained in accordance with established procedures.

Whilst there are obviously constraints imposed on the operation and maintenance of such systems when used on offshore installations and storage vessels, and whilst such constraints could increase the measurement uncertainties, the range of figures given above provide a realistic basis for comparison with figures derived for tank gauge systems.

In this comparison the quantities involved are gross measurements of oil expressed in standard volume. In other words the assessment of water quantity is not included since it is assumed that the same figure derived from a properly installed pipeline sampling system on the storage vessel can be used in both cases.

3.2 Measurement by Tank Gauge Systems

3.2.1 Factors affecting uncertainty

The standard volume of oil contained within a storage tank is calculated as:

$V = h.A.vcf$

where

V = standard volume of oil

h = level of oil within the tank

A = cross-sectional area of tank

vcf = volume correction factor to correct measured volume to standard volume

The main factors affecting each of these variables need to be considered in order to arrive at an overall uncertainty on the standard volume figure. As far as the oil level is concerned the main factors are:

a) the characteristics of the gauge by which level is determined.

b) the motion of the fluid within the tank.

The fluid will move from pitching and rolling of the storage vessel. Such movements will result in the need for trim and list corrections which are included in the tank calibration tables. The motion of the vessel may also produce surface waves or ripples.

The cross-sectional area is reflected in the tank calibration figures. It is not a single figure but is a composite of all areas from the lowest liquid level of the tank to the surface of the oil. It includes corrections for deadwood within the tank. The factor which dominates the uncertainty of the cross-sectional area is the method by which the calibration has been determined. The calibration may be determined from drawings, or individual tanks may be physically calibrated. The resultant uncertainties are very different. Temperature, and its calculated influence on the tank dimensions between calibration and use will play a minor role in the uncertainty.

The volume correction factor will have an uncertainty which is characteristic of the oil being stored. The use of the standard tables produces this oil specific uncertainty. Temperature plays the dominant part in the determination of volume correction factor and, therefore, dominates the uncertainty. Oil density plays a

relatively minor role.

In many operations the determination of the quantity of oil transferred from a tank requires two sets of measurements, one prior to and one on completion of the transfer. When the tank is empty on completion of the transfer a different uncertainty will result from that which arises when the tank is part full on completion.

During the transfer a small quantity of oil may be retained as clingage on the tank walls. This will produce a small systematic overstatement of all transfer quantities.

All of these factors are considered in more detail below.

3.2.2 Tank Contents Level

Many storage vessel systems employ radar gauges; these are ullaging devices with a claimed uncertainty of +/-1mm. Although this figure may be achievable under ideal conditions, it is considered that a figure of +/-3mm is more realistic in practice. This will be used for the base uncertainty calculations when the liquid surface is stationary.

Liquid surface movements can arise as ripples or waves. These might occur due to wave action of the sea during a transfer operation. Such movements will increase the uncertainty in the level measurement.

A second type of liquid movement will arise from the fact that the tanks do not retain the same orientation to the horizontal during a transfer. Such changes occur slowly and result in the need for trim and list corrections, which are a normal part of transfer operations. Corrections for trim and list variations are included within all marine tank calibration tables. They may need to be determined when wave conditions are quite severe which leads to uncertainty in the readings and an increase in the overall measurement uncertainty whenever conditions are adverse. Although the effect of trim and list is to vary the liquid level it is simpler to consider this under calibration considerations, rather than here under level factors.

Surface movements in the form of waves or ripples, arising from tank movement, must be considered as contributing to liquid level uncertainty. The radar gauge electronics may be dampened to provide either an instantaneous reading at low damping, or an effective average of several readings at high damping. The manufacturers claim that the latter will allow for the level to be measured with waves or ripples with minimal increase in uncertainty. Such a claim could be optimistic and a figure of +/-10mm is considered to be realistic under adverse weather conditions when surface waves are present on the oil. It will be seen below that even this conservative estimate does not have a huge influence on the overall transfer uncertainty.

If we assume nominal tank dimensions of 17.5 x 32 x 25m high, the volume of an individual tank is 14000 cubic metres. An uncertainty of 3mm in level is equivalent

to an uncertainty of 1.7 cubic metres or 0.01% of total tank volume. This is relatively insignificant in percentage terms when the tank is full. Even when the more conservative figure of 10mm is taken, for the situation in rough weather conditions, the uncertainty on a full tank is only 0.04%. As the level drops these uncertainties become more significant percentages of the volume. The procedures adopted during transfers will influence the overall significance of level measurement and will be considered later.

3.2.3 Tank Calibration

Most marine tankers are not calibrated physically and tank volume tables are determined from the manufacturer's dimensions. These pseudo calibrations are compared with metered oil quantities on most occasions that the tanker is loaded at a crude oil terminal. The average of 10 load ratios allows an average ratio known as the vessel experience factor to be established. This factor is effectively a calibration ratio for the complete tanker. Part cargoes are specifically excluded from the experience factor determination.

Experience indicates that the pseudo calibrations referred to above overestimate cargo quantities by about 0.2%(see ref 1). However the variability which arises with uncalibrated vessels is a key factor in this paper. A database has been maintained over a period of eight years tracing voyage measurements from bill of lading to outturn. The paper referenced above was based upon this data . The database covers some 4000 voyages per year. Load data allows average load ratios to be determined for all vessels which have 10 or more voyages in a given year. Fig 5 shows the distribution of such average ratios from a large sample of voyages in 1993.

This histogram shows that at the 95% confidence level the ratio varies from below 0.996 to about 1.006, representing a range of +/-0.5%. If dimensional checks were conducted during the construction of a storage vessel it is possible that some improvement in the uncertainty could be achieved, but a figure of +/-0.3% for the uncertainty of volume tables for uncalibrated complete vessels is considered to be a minimum value. This value has been assumed in all analysis from this point.

If we assume that the storage vessel contains 10 tanks, each individual tank will have an uncertainty of $+/-0.3\% * \sqrt{10}$. The individual tank uncertainty will be above that of the whole vessel (on a percentage basis) owing to randomisation effects. This figure of +/-1.0% is a realistic assessment of the likely individual tank uncertainties which will apply all the way up the tank for each volume/level figure.

Claims for the volume uncertainty of an individual calibrated tank range between +/-0.1 and 0.3%. In the past calibration was undertaken using tapes, a process which is now regarded as expensive, dangerous and less accurate than the optical techniques now available. Whilst these latest methods may be able to achieve uncertainties at the lower end of the range, a figure of +/-0.3% will nevertheless be used for this analysis.

Marine tankers are not calibrated because the use of vessel experience factors can limit the significance of any bias in the ship's tables. However where a storage vessel is used as the basis of measurement, experience factors will not be available and a physical calibration is to be recommended.

Tank volume tables are calculated at a specific temperature and a small correction is needed to account for changes in wall temperature from the calibration temperature. The correction itself is small and any uncertainty arising from temperature measurement or the correction calculation is below 0.1%.

3.2.4 Trim and List Corrections

Tank volume tables, whether derived from drawings or from calibration, always include corrections for trim and list. In a storage vessel the orientation of the vessel to the horizontal will change as the tanks are emptied during a transfer. Trim and list corrections will be an essential part of the calculation process. Unfortunately the determination of trim and list on the open sea is not easy. These figures must be taken prior to the start of the transfer and, if the tanks are not completely emptied, after the transfer has finished. The calculation of uncertainty requires a knowledge of the gauge positions within the tanks as well as information on the methods of trim and list measurement. In the circumstances the best compromise is to consider how an error in, for example, the trim reading affects the liquid level which is measured. A pessimistic assumption of a 20mm error produces a figure of 0.1% of actual volume. This is considered to be a realistic assessment of the additional uncertainty arising from trim and list readings on the open sea.

3.2.5 Volume Correction Factor

Temperature is by far the most important factor in determining the vcf uncertainty. Although the measurement device used plays a small part in this, the dominant factor by far is the existence of temperature gradients within the oil. The gradients may exist both vertically and horizontally and although temperature is normally measured at three levels within the tank, this does not overcome all the problems of vertical gradients and none of the problems of horizontal gradients.

It is generally considered that measuring temperature in one vertical line will give a temperature reading with an uncertainty of +/-1 degC. Such a variation is the equivalent of 0.1% in the vcf tables at a density around 820kg/m3. The uncertainty of each temperature measurement device is well below 1 degC and may be considered to be included in the overall figure of 0.1% on volume.

Density has a very small influence. A change below 0.01% on volume would occur for a 10 kg/m3 variation in density and may be ignored compared with the temperature effect.

The tables themselves, which are used for crude oil vcf determinations, have an inherent uncertainty. In the range 0 to 30 degC a figure of +/-0.05% is quoted in the API Manual of Petroleum Measurement Standards, Chapter 11.1.

3.3 Overall Uncertainty of Tank Measurements

Having considered the individual contributions to a single set of measurements leading to a standard volume uncertainty, it is necessary to put all these together to give an overall figure. First the individual figures must be characterised as random or systematic.

The figures derived above may be summarised as follows:

		% uncertainty full tank	nature
Level measurement	calm	0.01	random
Level measurement	rough	0.04	random
Tank tables	ship drawings	1.0	systematic
Tank tables	calibration	0.3	systematic
Trim/list reading		0.1	random
vcf temperature		0.1	random
vcf tables		0.05	systematic

Other factors are insignificant compared with these in the determination of a single tank standard volume figure.

The overall systematic uncertainty from these figures is:

for an uncalibrated tank	1.05%
for a calibrated tank	0.35%

The overall random uncertainty derived from quadrature addition is:

calm conditions	0.10%
rough conditions	0.15%

It is assumed that under calm conditions no uncertainty in trim and list will arise.

The figures relate to the percentage uncertainty in standard volume determination on a full single tank. **It is clear that overwhelmingly the most significant factor lies in tank calibration.**

With small fractions of tank filled with oil, the level measurement becomes much more significant. In this case the uncertainty of the level measurement is inversely proportional to the percentage of the tank that is filled. When a tank is 10% full of oil the level uncertainties are:

calm conditions	0.1%
rough conditions	0.4%

These lead to overall random uncertainties for a single volume measurement with around 10% of the tank full as:

calm conditions	0.14%
rough conditions	0.42%

The figures derived above may be used to determine the uncertainty of a transfer from the storage vessel, as described in the next section.

The key message from this section is, however, that the storage vessel should be calibrated if systematic biases are to be avoided. Experience shows that it is unlikely to be possible to determine the equivalent of a vessel experience factor for a storage vessel against the vessels which are loaded since the range of tanker load ratios is too wide.

3.4 Transfer Uncertainties

The figures for measurement uncertainties in a single tank may be used as the basis for determining the overall uncertainty of a transfer from a storage vessel. In fact transfer uncertainties have been calculated for a number of different conditions as follows:

Best case - transfer of a large quantity of oil by completely emptying several tanks under calm conditions. Assume a cargo of 112000 cubic metres is transferred by completely emptying 8 tanks of the storage vessel. The overall uncertainties of the transfer would be:

Systematic

Uncalibrated tanks	$1.0/\sqrt{8} + 0.05\% = 0.4\%$
Calibrated tanks	$0.3/\sqrt{8} + 0.05\% = 0.16\%$

Random (calm sea) $0.1/\sqrt{8}\% = 0.04\%$

Overall

Uncalibrated tanks	0.44%
Calibrated tanks	0.20%

The randomisation of the tank calibrations between tanks arises because, although the bias is systematic within each tank, these biases are random between tanks. No such randomisation occurs with the vcf table bias, since the oil is identical in all tanks.

Worst case - transfer of part of a single tank under rough sea conditions. For the transfer of 90% of a single tank the uncertainties would be:

Systematic

Uncalibrated tanks	1.05%
Calibrated tanks	0.35%

Random (rough sea) 0.17%

Overall
Uncalibrated tanks 1.22%
Calibrated tanks 0.52%

Intermediate case - consider a transfer of 56000 cubic metres derived by completely emptying 3 tanks and 50% emptying 2 further tanks under rough conditions.

Overall Uncertainties
Uncalibrated tanks 0.57%
Calibrated tanks 0.25%

Other cases may be determined by following similar procedures.

A number of important conclusions can be drawn from these figures:

a) calibration of the tanks is the biggest influence in minimising systematic errors.
b) tanks should be fully emptied wherever possible.
c) the largest possible transfers drawn from as many tanks as possible will minimise uncertainty.
d) the influence of sea state is not as important as the above factors.

In fact it may be concluded from this analysis that provided large volumes are transferred from a number of calibrated tanks which are completely emptied, then overall uncertainties close to those achieved by metering can be achieved even in rough sea conditions.

4 OPERATING EXPERIENCE

Detailed information comparing the measurement of transfers from storage vessels by metering and tank gauge systems is not readily available. However a limited analysis has been carried out on data derived from twenty consecutive transfers from one installation. The results are shown as differences between metered and tank gauge figures expressed as a percentage of the metered figures. These results are presented as a frequency distribution in fig 6. This distribution is seen to have a Gaussian form (indicating that random effects dominate), producing a standard deviation of 0.13%. However it is also apparent that there is a systematic difference between the two sets of measurements, averaging -0.18%.

The systematic difference is consistent with the data shown in fig 5 which indicates that uncalibrated vessels tend to produce an overestimation of cargo quantities averaging about 0.2%. In this case the vessel was not calibrated so the difference should not be seen as surprising.

The standard deviation of 0.13% represents the combined random variations of the metering and tank gauging figures. Without a detailed analysis it is not possible to assign specific levels of uncertainty to either method but the results are not inconsistent with the figures or conclusions derived in the preceding sections.

5 POTENTIAL DEVELOPMENTS AND IMPROVEMENTS

The analyses presented above show the major contributors to the uncertainty of measurement by storage vessel tank gauge systems. Whilst calibration of the tanks offers the greatest improvement, there are nevertheless a number of areas where smaller but worthwhile improvements could be achieved. Two of these are considered below.

Temperature measurement - the uncertainty of vcf determination is mainly influenced by the uncertainties of temperature measurement in the vessel's tanks. Improvements in this area can be achieved by increasing the number and changing the distribution of temperature probes in the tanks. Potentially this could improve the random uncertainty on a single tank volume by 0.04% and on a typical transfer quantity by 0.02%.

Level measurement - errors in level measurement contribute less to the overall uncertainty than temperature errors. Even so the additional uncertainty arising in rough sea conditions could be reduced through improvements in this area. For example the use of a second tank gauge in each tank (although expensive) would provide independent verification of measured volumes. Furthermore if the gauges were correctly located, much more confidence could be placed in the trim and list figures through the extra information available. If this approach was not considered feasible then improvements in trim and list measurement in rough sea conditions should be considered.

6 PRACTICAL CONSIDERATIONS

To perform successfully, any measurement system must be correctly designed, installed and maintained. The tank gauging systems discussed in this paper are no exception to this; indeed it is apparent that the complete vessel must be regarded as a measurement device and the various components designed accordingly. A number of practical considerations based on experience and good measurement practice are highlighted below.

a) It is important that it should be possible to isolate tanks completely and securely from one another. Where appropriate therefore, bottom lines should be fitted from the outset with double block and bleed valves so that isolation can be monitored.

b) Where problems of clingage of oil on the tank walls occur, a systematic overstatement of the transfer quantities will result. This problem is overcome in marine tankers by the use of crude oil washing. The need for the appropriate equipment on the storage vessel could be determined at the design stage from a knowledge of the characteristics of the oil.

c) It is normal practice to de-bottom the tanks to remove free water before the start of any transfer. This water is generally collected in a separate tank and the residual oil allowed to separate before the clean water is discharged. This water

plays no part in the transfer from storage vessel to tanker and is therefore not measured as part of the custody transfer. However, the suspended water which is transferred with the cargo must be accounted for . This is normally achieved by analysing samples drawn by an automatic sampler mounted in the storage vessel transfer line. As far as the comparisons in this paper are concerned, this method of water determination is equally applicable to metering and tank gauge systems, so the uncertainties involved are the same for both methods.

d) The operational requirements for metering and tank gauge systems are to some extent contradictory. To prevent air being drawn through a metering system (a process which will produce measurement errors) it is normal practice to leave 1-2 metres of oil in each storage tank. The remaining oil may then be collected in a single tank from which the transfer is completed. By contrast the optimum procedure for tank gauging is to empty the storage tanks completely so that measurements in partially empty tanks are avoided. As noted above such additional measurements increase the uncertainty of the volume determination; indeed experience confirms that radar gauges can give unreliable results at low liquid levels in storage vessels. However where tanks are emptied completely, procedures must be introduced to ensure that the ship's bottom lines are in the same state before and after a transfer.

One consequence of these arguments is that where metering and tank gauge figures for the same transfers are compared, the procedures which must be adopted for the metering system are likely to increase the uncertainty of the tank gauge measurements.

e) Procedures for monitoring metering systems are well established. Control charts are employed on many offshore installations and sophisticated statistical techniques are also available. The marine tanker industry has developed basic monitoring procedures for loadings and discharges, but as noted above such basic procedures are unlikely to be applicable to storage vessel transfers. Nevertheless monitoring is essential to give the earliest possible warning of problems and more advanced methods should accordingly be considered.

7 CONCLUSIONS

An uncertainty analysis indicates that storage vessel tank gauge systems are capable of achieving uncertainties similar to those of metering systems. The limited practical data available tends to support this.

A number of improvements in both the design and operating procedures of tank gauge based systems are proposed. These together with the practical points which are highlighted will ensure that such systems are able to achieve optimum performance.

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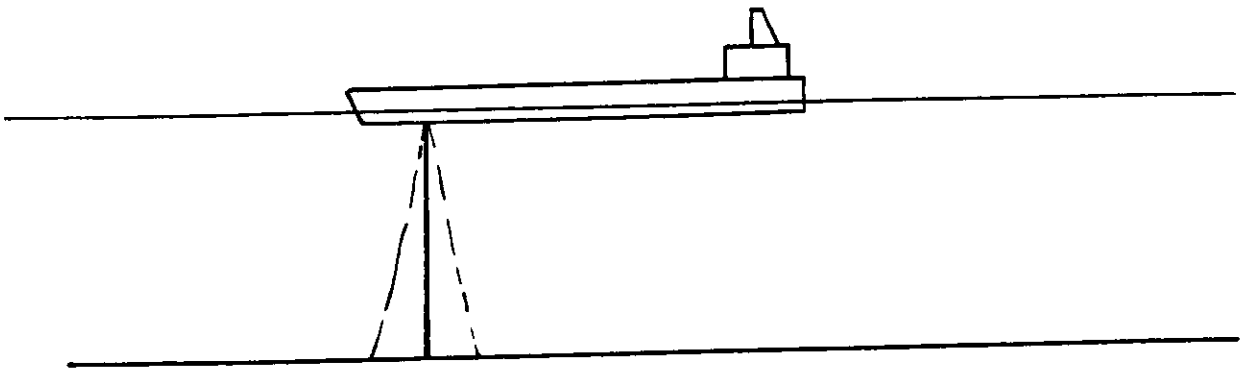


Fig 1 SWOPS Vessel

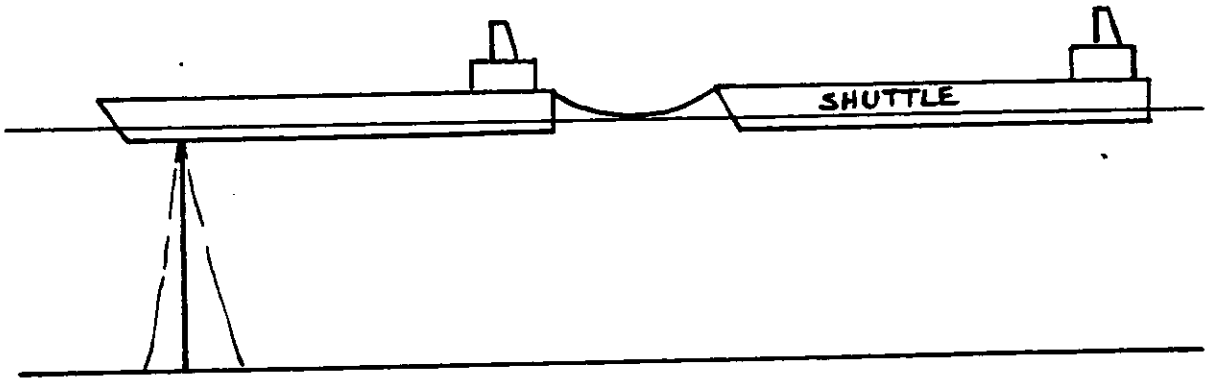


Fig 2 Floating Production and Storage

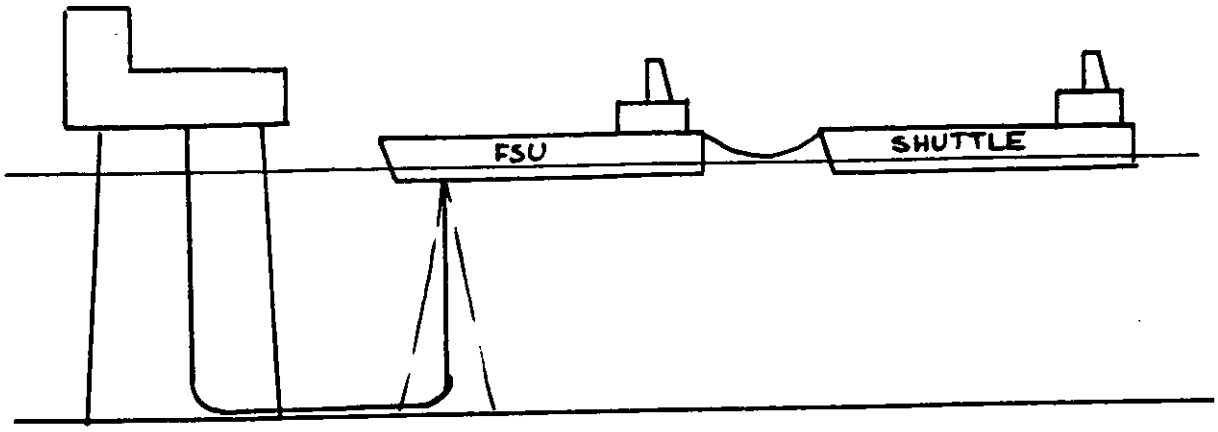


Fig 3 Floating Storage

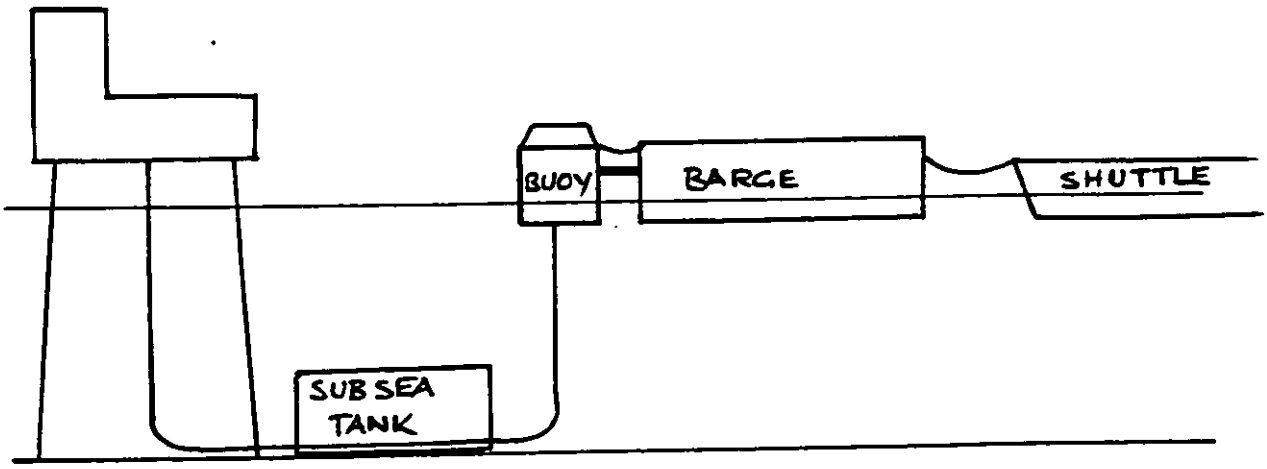


Fig 4 Barge / Subsea Tank

Fig 5 Vessel VEF Values

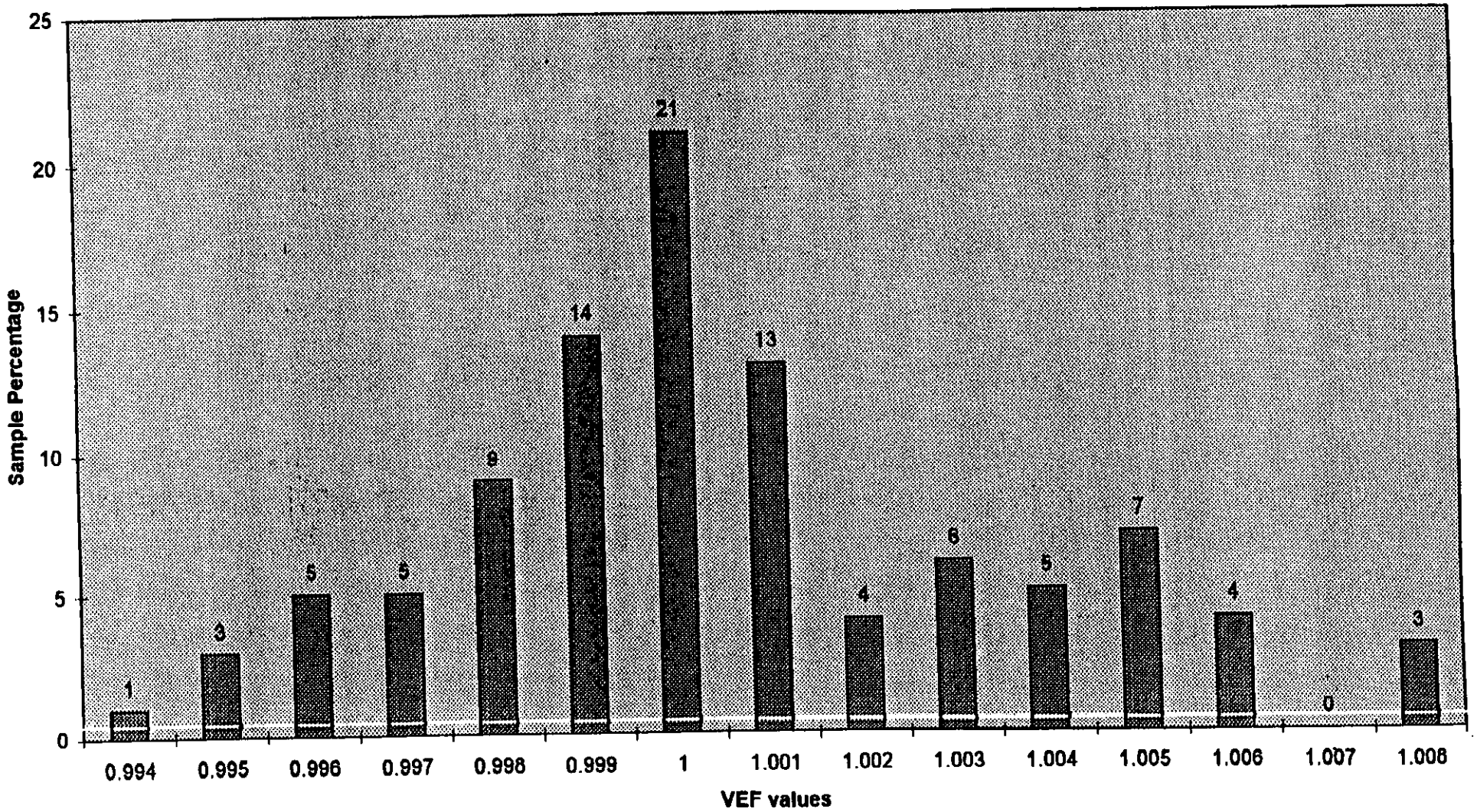
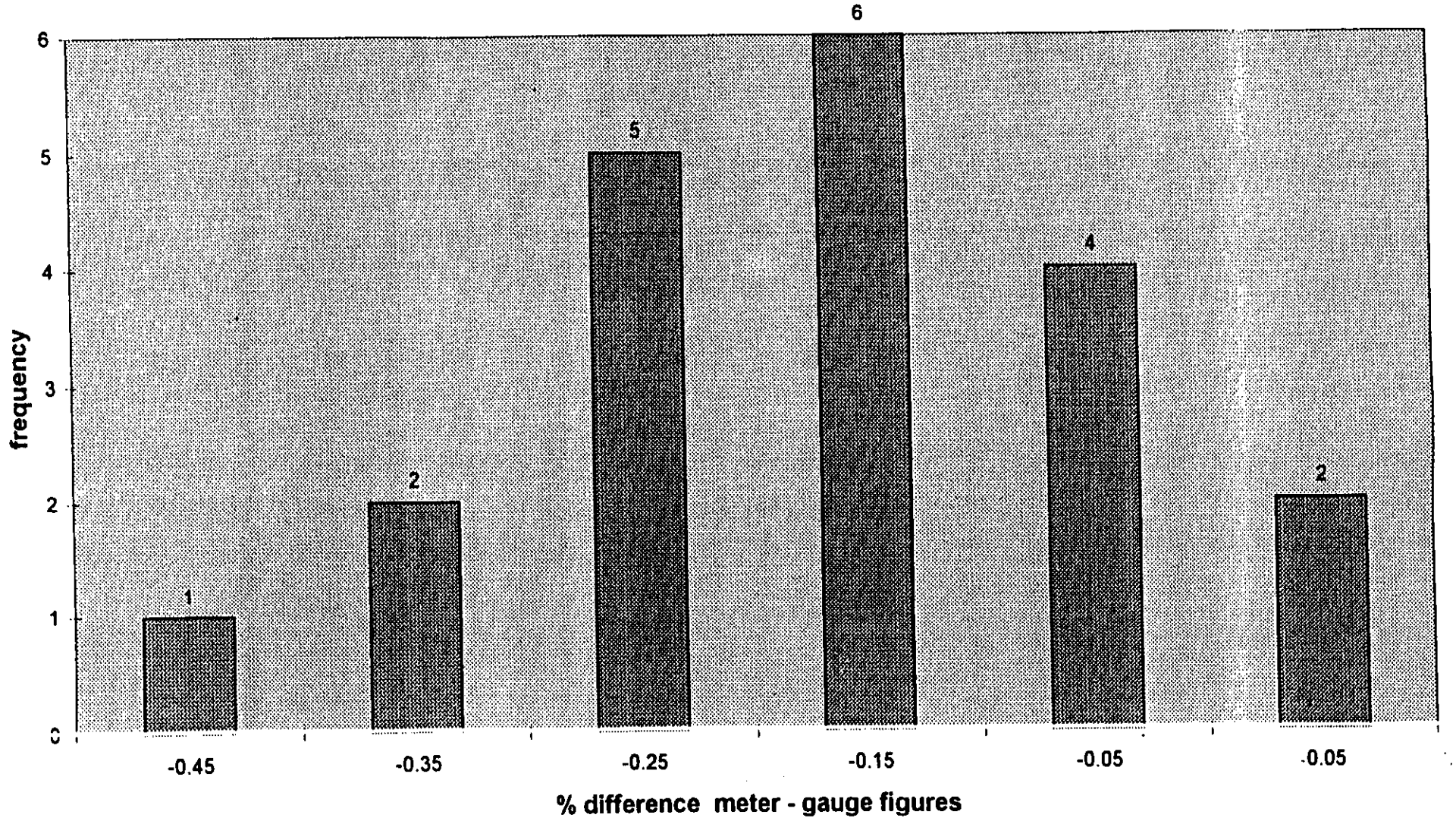


Fig 6 Meter/Tank Gauge Differences



Main Index

North Sea FLOW Measurement Workshop 1995

Paper 8:

ENHANCED SYSTEM FOR CRUDE OIL MASS FLOW MEASUREMENT

2.2

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ENHANCED SYSTEM FOR CRUDE OIL MASS FLOW MEASUREMENTS

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Scott Gaisford	Multi - Fluid Inc.
Rune Sørhus	Multi - Fluid International AS

SUMMARY

A new system is proposed for enhancing and simplifying the metering of oil and water flow rates in liquid lines containing mixtures of water and crude oil, including liquid lines from two and three phase separators. By combining a Coriolis and a MFI WaterCut Meter, one achieves a measurement system capable of more accurate measurements of oil and water flow rates than is possible with either device alone, while at the same time reducing maintenance and calibration requirements.

1. INTRODUCTION

It is of great interest for Measurement Engineers to simplify the systems for metering oil mass-flow and the watercontent in the oil with high accuracy. During the last few years, several new technologies and products have been introduced, making a simplification possible. The system proposed in this paper is thoroughly tested and verified in a series of successful tests and installations, and is expected to help operators reduce operating expenditures and improve their profit. The system consists of a Coriolis Meter and a MFI WaterCut Meter linked together in such a way that the two instruments together provide better results then they would separately. Coriolis Meters have demonstrated the ability to accurately measure mass flow rates, even to fiscal specifications. The MFI WaterCut Meter is also used for fiscal metering and in custody transfer applications.

A Coriolis Meter can be used to determine the water cut of oil. The water cut is determined by comparing the mixture density to reference densities of free oil and water. However, significant errors can be encountered if the densities of the oil or water should vary from the calibrated reference values. The errors are magnified as the density difference between the oil and the water decreases.

Water cut meters, based on electrical measurements of oil/water mixtures, are in general much more accurate than the method described above, but tend to behave similarly. Their readings shift according to changes in the dielectric properties of the pure oil and the water. The dielectric variations are in turn related to oil and water density variations.

This paper outlines how the AutoZero function of the MFI WaterCut Meter overcomes this problem and enables a measurement system based on a Coriolis meter

and a MFI WaterCut meter to measure correct water and oil flow rates, even if the density of oil and water changes over time.

2. TRADITIONAL MASS FLOW MEASUREMENT SYSTEM

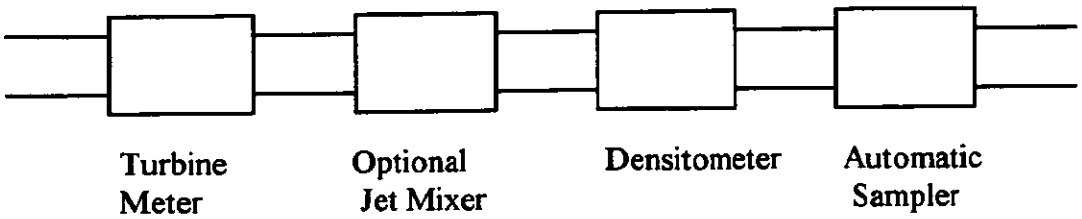

Figure 1

A traditional mass flow measurement system may consist of a flowmeter such as a turbine meter, a mixer, a densitometer and an automatic sampler. The turbine meter measures the total volumetric flow rate. This result, when combined with the mixture density from the densitometer and the water cut from the automatic sampler, gives the mass flow rates of water and oil.

There are several weaknesses of this system. The automatic sampler, turbine meter and the Jet Mixer have moving parts which require regular maintenance in order to obtain the desired accuracy. Secondly, the automatic sampler requires a technician on site in order to collect and analyse the daily, weekly and monthly samples. Finally, the only on-line information the system supplies is total volume flow and mixture density. Oil density, oil mass-flow rate and water mass-flow rate must be calculated off-line.

3. ENHANCED MASS FLOW MEASUREMENT SYSTEM

3.1 Basic Principles of the Coriolis Meter

A Coriolis meter measures the total mass flow rate and the mixture density. The Coriolis meter sensor is a vibrating, twisting tube. When liquid is flowing through a tube which is forced to resonate at it's natural frequency, it causes the tube to twist. This twisting effect characteristics is called the Coriolis effect. According to Newton's Second Law of Motion, the amount of tube twist is directly proportional to the mass flow rate of the liquid flowing through the tube. The density measurement is obtained by mounting the tube such that it is fixed at one end and free at the other end. This configuration can be envisioned as a spring and mass assembly. Once placed in motion, a spring and mass assembly will vibrate at its resonant frequency. The resonant frequency is a function of the mass of the assembly, and since the volume of the tube is known, the density of the liquid flowing through the tube can be determined.

3.2 Basic Principles of the MFI WaterCut Meter

The MFI WaterCut Meter uses a unique, patented microwave technology that measures the dielectric constant of oil/water mixtures with an extremely high degree of accuracy and resolution. From this measurement, together with the measured temperature, the meter can determine the volume fractions of water and oil in a mixture. The meter is calibrated by entering data which enables the meter to determine the respective dielectric constants of the oil and water.

The Meter uses the resonant cavity method to measure the mixtures dielectric constant. A resonant cavity is a closed structure from which electromagnetic energy cannot escape. Instead it reflects back and fourth until it is dissipated. At characteristic frequencies, the electromagnetic waves constructively interfere with one another (or resonate) and produce a very narrow, high output power peak. By measuring the frequency of the resonance, one can derive the dielectric constant of the material in the pipe. The WaterCut sensor is constructed in such a way that the oil/water mixture may easily flow through the sensor, whereas the electromagnetic energy cannot escape.

3.3 The AutoZero setting function.

The MFI Meter must be field configured with the density of the dry oil and the conductivity of the water. The oil density is used to determine the dielectric constant of oil, which defines the zero point. The conductivity of water is used to calculate the dielectric constant of water, which defines the span of the measurement. As a result of extensive research and testing, Multi - Fluid has determined that the high frequency dielectric constant of a dry hydrocarbon liquid is closely correlated to its density as shown in figure 2.

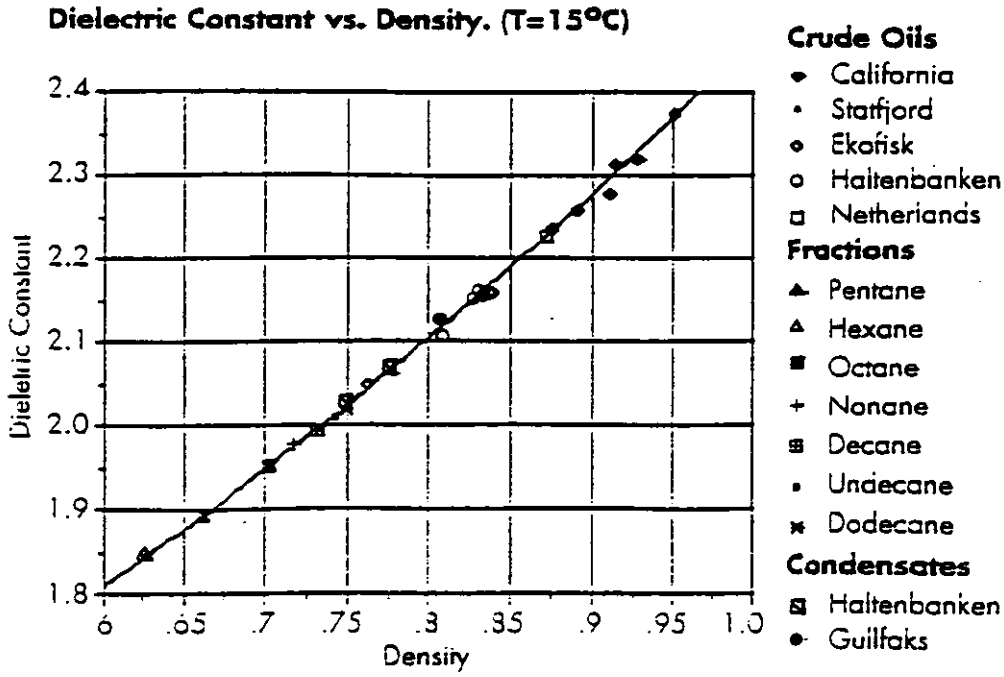

Figure 2

As implied by Figure 2, the MFI WaterCut meter is in principle sensitive to the variations in dry oil density, though the sensitivity is far less than the sensitivity of a density based watercut measurement. However, the patented AutoZero function of the MFI Meter overcomes this problem. By using the relationship in figure 2 and linking the WaterCut Meter with a densitometer, the MFI Meter can dynamically adjust its zero setting, defined by the dry oil density, according to the measured density of the process stream, and thereby leaving the operation of the Meter fully automatic. In operation the AutoZero function works as follows :

1) The MFI Meter reads the mixture (oil + water) density from the densitometer.
2) It measures the raw dielectric constant of the mixture using the microwave sensor.
3) It measures temperature of the mixture.
3) Finally, it solves a complex set of simultaneous equations to determine the correct dry oil density and the watercontent of the particular mixture.

Thus, the MFI WaterCut Meter with AutoZero dynamically measures the correct watercontent and the dry oil density of a mixture when the dry oil density and the watercontent is changing over time, or more correctly, the Meter measures the density of the *non-water* phase. Consequently, the Meter may measure the watercontent and either a) the dry oil density *or* b) the amount of free gas in the pipe if the dry oil density is constant.

3.4 Enhanced Crude Oil Mass Flow Measurement system.

By combining a Coriolis Meter with a WaterCut meter with AutoZero, one obtain a very compact oil mass-flow measurement system as shown in figure 3.

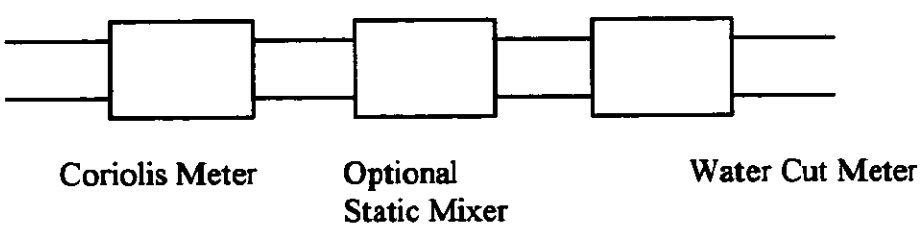

Figure 3

The combined system measures the following parameters, assuming that the mixture density and dielectric constant are measured at the same temperature and pressure :

Coriolis Meter :	Total Mass Flow Rate Mixture Density
WaterCut Meter :	%Water by volume Dry oil density Temperature

Hence the following parameters can be calculated assuming a constant water density :

Oil Volume Flow
Oil Mass Flow.
Water Volume Flow
Water Mass Flow

The combined system has several advantages :

1. There are no moving parts. This eliminates most maintenance and reduces cost.
2. The WaterCut Meter is able to perform all the necessary calculations and transmit the results on either analogue 4-20 mA outputs, frequency outputs, or a digital RS422 serial communication port. Hence a minimum of additional instrumentation and software is required to install and use the system.
3. The measurement system gives in-line, real time information of all the above mentioned values making it possible to improve process efficiency.
4. The system can be completely field mounted, with no need for dedicated control room equipment.

4. APPLICATIONS

Custody Transfer

Coriolis Meters have shown that they are capable to measure mass flow to fiscal standards, and meters are already in use on such applications. However, in order to determine the watercut, an automatic sampler is required. Consequently the system requires a technician on site in order to collect and analyse the daily, weekly and monthly samples, and furthermore, the system only gives in-line information about the total mass flow. The MFI WaterCut Meter with AutoZero is in the process of being approved for custody transfer in UK and Norway. Next, a complete fully automatic field mounted , in-line Mass Flow Measurement System based on a Coriolis Meter and a WaterCut Meter could be used for custody transfer.

Separator Liquid Outlets.

The amount of water in the oil-leg at test and production separators may vary over time due to water "carry-over" or depending on how strong the binding is between water and oil. Furthermore, there may be some free gas in the oil-leg, particular in low pressure systems. A traditional system for measuring the flow rate from an oil-leg on a test or production separator may be by using a turbinemeter or a ultra-sound based meter to measure the total volume flow, and perhaps an in-line densitometer to measure the density in order to obtain the mass flow rate. Alternatively a Coriolis Meter may be used to fulfill both these requirements.

The MFI WaterCut Meter with AutoZero in combination with a Coriolis Meter measures the correct water and oil mass flow rates even if the dry oil density is changing. Moreover, the WaterCut meter functions with free gas present. Depending on the mixing, the meter may work with 3 - 5 % of free gas, or even higher, this mainly being limited by the Coriolis Meter. Based on the measured density from the Coriolis meter, the WaterCut meter is able to measure the correct watercut in addition to the density of the non-water phase. This information could be used to calculate the amount of free gas if the dry oil density is known, hence more accurate measurements of the oil and water mass flow rates could be obtained.

Multi - Phase Metering

A simple Multiphase metering system could be built by separating the gas from the liquid. The gas could be measured separately and the oil and water rates could then be measured by a Coriolis/WaterCut Meter configuration as shown in figure 4 below.

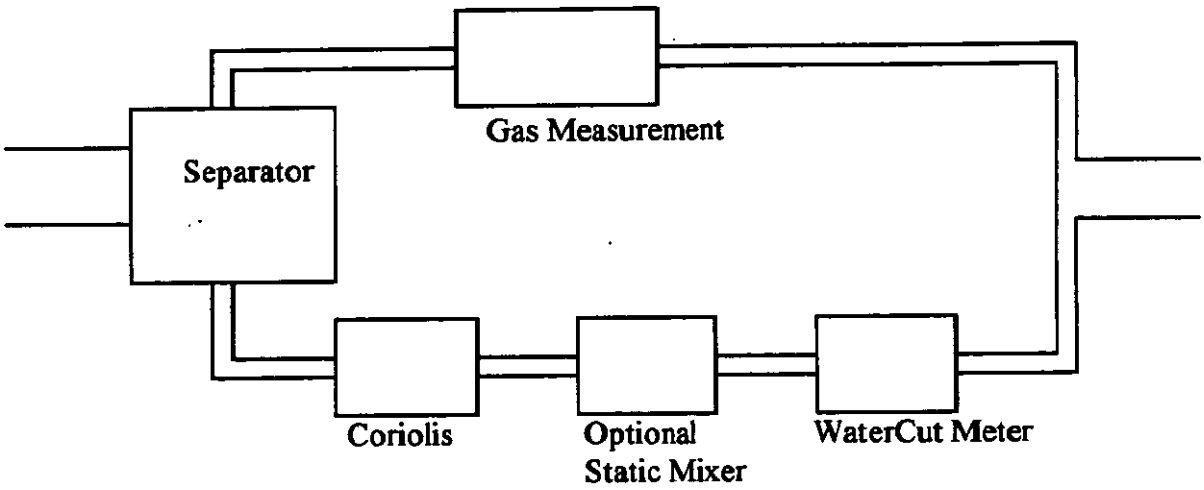

Figure 4

Because the Coriolis / WaterCut combination is able to function properly with some free gas in the liquid, the separator does not need to separate out all the gas from the liquid line, hence the separator could be a simple cyclone separator. The water and oil rates together with the remaining gas in the liquid leg are measured by the Coriolis / WaterCut Meter. The MFI WaterCut Meter has the capability of performing all the necessary calculations for the whole system.

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North Sea FLOW Measurement Workshop 1995

Paper 9:

METERING OF SATELLITE FIELD PRODUCTION WITHIN THE ALWYN AREA

2.3

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METERING OF SATELLITE FIELD PRODUCTION WITHIN THE ALWYN AREA

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Summary

The economic development of the Alwyn South fields called for an unconventional metering approach. The metering options studied resulted in the flow sampling technique being adopted. The innovative method of implementation provides the level of performance required within the constraints of a minimum facilities project philosophy.

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Introduction

The Alwyn Area fields are operated by Total Oil Marine Plc which is the British Exploration and Production subsidiary of the worldwide Total Group. The Alwyn North field situated primarily in block 3/9A in the UK Northern North Sea has been producing since November 1987. Oil / condensate is exported via the Ninian Pipeline to Sullom Voe, gas is exported via the Frigg Transportation System to St. Fergus. Gas export rates have typically been 9 million standard m^3 per day during winter months but oil production has declined in recent years from 11000 tonnes / day (100,000 bbls / day) to approximately 3600 tonnes / day (30000 bbls / day).

The Alwyn North Extension (ANE) comprising 3 subsea wells was brought on stream during 1992 and boosted liquid export. This development was within the original Alwyn North development and Petroleum Revenue Tax (PRT) boundary. For this reason no additional metering was required, hydrocarbons being allocated by volume to each producing well.

The forecast decline in Alwyn North export liquids resulted in spare processing capacity on the platform.

To the South of Alwyn North are three fields collectively termed Alwyn South (see Fig. 1).

Alwyn South reserves are comprised of three distinct areas:

The Western area is largely oil / associated gas and is named Dunbar.

The Eastern area has two gas / condensate fields named Ellon and Grant.

The development plan for Dunbar, Ellon and Grant called for these marginal fields to be produced as satellites of Alwyn North. Fluids from these satellites would be processed on Alwyn North, injection water and power would be supplied from the main installation.

The economic constraints within the development plan only allowed for a minimum facilities platform at Dunbar with subsea wells for Ellon and Grant tied into the Dunbar platform. Permanent facilities on Dunbar are minimised by the use of a Tender Support Vessel during the drilling phase. Export to Alwyn North is via an insulated multiphase pipeline (see Figs 2 & 3).

Although the Alwyn South fields have the same ownership as Alwyn North - 1/3 Total Oil Marine (Operator) and 2/3 Elf UK, they fall in different PRT zones and are subject to different transportation and sales agreements.

Metering Study

In order to fulfil metering requirements within the economic constraints of Alwyn South, three main approaches were studied:

a) Full Fiscal Standard Scheme

Install additional process streams to separate and dry the gaseous hydrocarbons prior to additional compression and export metering. Install additional produced water handling and liquid pumps / export metering.

b) First Stage Separator Metering Scheme

The existing export gas and export liquid metering systems on Alwyn North would measure the commingled Alwyn South / Alwyn North hydrocarbons. The allocation of production to each of the four PRT zones would be based on the continuous metering of effluent from dedicated first stage separators.

Three first stage separators would be required on the Dunbar platform each with gas, oil and water metering / analysis. The two first stage separators on Alwyn North would require upgraded metering / analysis.

In addition a test separator would be required on the Dunbar platform for well testing of the Dunbar, Ellon and Grant wells. A further separator is required on NAB to allow Alwyn South fluids to be fed into the Alwyn North process due to the distinct oil and gas trains and recycle loops.

c) Flow Sampling Scheme

The existing export gas and export liquid metering systems on Alwyn North would measure the commingled Alwyn South / Alwyn North hydrocarbons.

Each well in the Alwyn area would in turn flow through a test separator in order to determine the well production rate at a particular well head flowing pressure measured upstream of the production choke. Continuous measurement of well head flowing pressure would allow each wells production to be calculated on a daily basis. Allocating metered export to each well in proportion to its production would allow field production to be calculated.

One test separator on the Dunbar platform would allow each of the Dunbar, Ellon and Grant wells to be tested monthly. The two existing test separators on the Alwyn North Process Platform (NAB) would continue to test Alwyn North wells monthly.

Selection of Scheme

The full Fiscal standard scheme with large scale associated process plant made the development of Alwyn South fields uneconomic. This scheme was ruled out at an early stage due to negative project economies.

The choice of metering scheme was made from a study of the two main options of 1st stage separator metering and flow sampling.

In order to assess if one scheme could be justified over another the impact on measurement uncertainty was studied by an independent consultancy.

The initial reaction to this problem was to believe that the 1st stage separator method would have a far better measurement uncertainty as it is a continuous metering method. However, the two methods have many similarities which tend to diminish this advantage largely as a result of the Alwyn process plant having many recycle loops.

Hydrocarbons metered either at a 1st stage separator or at a test separator will have to pass through a similar amount of process equipment before it reaches the export metering facilities. There will therefore be a similar level of complexity and uncertainty associated with allocating metered export to each producing field.

The gas or liquid leaving a 1st stage or test separator will be processed to a similar level of efficiency. Oil will be contaminated with water and water contaminated with oil. Assuming 100% separation efficiency or gaining unrepresentative samples will result in additional measurement uncertainty.

An effective simulation of the flow of hydrocarbons through the process for allocation purposes may only be obtained by tracking hydrocarbon and inert components in an accurate manner. This means that the composition of each feed stream must have a representative analysis and the analysis of samples must be sufficiently detailed to identify the presence and properties of the heavier hydrocarbon components.

In addition to the above options, the use of multiphase metering was considered but in 1990 the technology was not considered sufficiently developed to allow reliable measurement to the required level of uncertainty. Multiphase meters could potentially have been used to measure the flows from each PRT zone and for well testing in place of a test separator. In view of the large potential for capital and operating cost savings, TOTAL continues to invest in multiphase metering R & D.

The following table shows a comparison of the uncertainties associated with each metering scheme. Although the values are considered as random and those associated with each element open to some fine tuning a useful trend results as all elements are common except one.

Item of Uncertainty	1st Stage Separator Metering	Flow Sampling
Gas Flow	2.5 %	2.5 %
Liquid Flow	2 %	2 %
Sampling Representivity	5 %	5 %
Sample Analysis	3 %	3 %
Interpolation of Well Test Results	0 %	5 %
Process Simulation	3 %	3 %
Combined	**7.3 %**	**8.8 %**

The difference in measurement uncertainty is due to interpolation of wellhead flowing pressure vs well flow rate from well testing. A figure of 5% is not considered achievable in the first 3 months of production but thereafter well test data should become more consistent as a trend develops.

The Alwyn North 1st stage oil separator (C-101) is injected with liquids separated from the gas process, this recycle loop is connected upstream of C-101. In addition to the difficulty in measuring the recycled fluids metering by difference would have to be performed, further increasing the uncertainty for 1st stage separator metering.

In order to meet the above measurement uncertainties substantial metering upgrades would have to be performed on the Alwyn North 1st stage separator meters where space and access are limited. Furthermore, 3 gas and 3 liquid metering systems would have to be installed, operated and maintained on Dunbar which was planned as a minimum facilities platform with minimum manning.

The outcome of the study was that the 1st stage separator metering scheme and associated additional 3 separators and metering systems could not be justified in terms of the perceived 1.5 % improvement in measurement uncertainty over flow sampling.

It was further considered that by installing well test metering equipment to a near fiscal standard on the 3 Alwyn Area test separators that the above uncertainties could be improved upon.

Method Adopted

The flow sampling scheme chosen allows individual well flow rates to be calculated from a continuous measurement of well head flowing pressure, that is the pressure upstream of the wellhead choke. The relationship between well head flowing pressure and well flow rate is developed by placing the well in series with the test separator. This allows the multiphase well flow to be separated into gas, oil and water, these effluent streams may then be measured using single phase meters. A well test is performed once the effluent flow rates have stabilised. Wellhead flowing pressure and flow rates are averaged over a six hour period, this establishes one point on the curve. Further well test points define the curve of wellhead flowing pressure versus well flowrate (see fig. 4). The points are achieved by adjusting the choke position. Increasing the choke opening increases well flow rate and results in a decrease in well head flowing pressure. Unfortunately this curve is not constant over time due to the gradual fall in reservoir pressure as hydrocarbons are extracted. The tests are repeated at regular intervals (typically monthly).

This process in effect creates a flow calibration curve for the choke dedicated to a particular well. Once well head flowing pressure has been averaged during a production day the corresponding well flow rate is taken from the curve. The most representative numbers are obtained by interpolating between well test curves for a known well head flowing pressure and date.

Samples taken during well testing may be analysed to provide a detailed composition of the well, when combined with the well flow rate hydrocarbon and inert component flowrates may be calculated.

A summation of the daily well flows may be used to estimate the production from a field but some of this flow is used as fuel or flare gas before export from Alwyn North. A more precise method is to calculate the amount of metered export oil or metered export gas from each producing field in proportion to estimated field production. However, this procedure requires careful modelling of the Alwyn process plant due to the interlinking between the oil and gas process equipment (see Fig. 5).

Years of experience in simulating the flow of fluids through the Alwyn North process plant resulted in optimum results from use of component mass flows. Plant feeds are tracked through separation and mixing to flare, fuel and export points.

An extensive study revealed that a method of allocating export, fuel and flare quantities would be effective if the following principles were adopted:

a) Component mass flows used from input to output.

b) A simplified process model used featuring three input feeds plus fuel and flare offtakes plus two export points and a water discharge point. The process model would use daily average pressures and temperatures measured on the plant (see Fig. 6).

c) Allocation coefficients would be calculated from process simulation results and used to allocate inputs in respect of export quantities. Flows would be allocated from a common feed to each well in proportion to the estimated well flow derived from well test curves.

d) Heavy hydrocarbon components would be characterised separately for each reservoir in order to improve the process simulation.

Metering System Design

There was a clear requirement from the allocation method study that mass flow metering was required at the outlets of each test separator. The measurement uncertainty study revealed that metering to near fiscal standards would be justified.

The following constraints were imposed on these goals by the Dunbar project philosophy and existing Alwyn North equipment:

a) Minimum facilities
b) Minimum manning
c) Consistent metering approach across the two Alwyn North test separators and Dunbar test separator.
d) Minimise upgrade work on Alwyn North.
e) Provide well test data that satisfies reservoir management as well as allocation requirements.

A consequence of minimum facilities was that one test separator would be used on Dunbar. This results in a wide range of gas and liquid flows being metered due to the nature of wells tested ranging from gas / condensate to oil / associated gas. Another consequence was that no booster pumps or fast loop pumps would be installed, automatic sampling systems were also ruled out due to their potential for extensive maintenance.

Test Separator Gas Flow Measurement

The gas at the test separator outlet is at saturation conditions. Multipath ultrasonic meters were not considered to be sufficiently developed at the time of the 1990 study. Conventional orifice meters would continue to be used on the Alwyn North test separators and this was the method selected as being appropriate for the Dunbar test separator gas flow.

The presence of liquid traces was accommodated by employing drain holes in the orifice plates and condensate trap pots in the impulse lines. 'Smart' differential pressure, absolute pressure and temperature transmitters are employed for their proven stability. Digital communication with the flow computer system uses the HART protocol to reduce uncertainties from analogue to digital conversion. The risk of liquid contamination prevented conventional density transducers being used. AGA(1) 8 is used to calculate density from the well composition plus measured pressure and compensated temperature. ISO 1567-1(2) is used to calculate mass flow rate. ISO 6976(3) is used to calculate standard density from the well composition.

The wide range of gas flows from the Dunbar test separator required three orifice meter runs of differing sizes. This allows any well to be tested by selecting the appropriate stream, orifice plate size changes are not required.

The two Alwyn North test separators were upgraded by installing the same instrumentation and computational methods as used on Dunbar. Although a smaller range of flow is required to be measured a minimum of two orifice plates are required in the single orifice meter run on each separator.

Test Separator Liquid Flow Measurement

Coriolis meters were selected to meter the mass flow of wet oil and oily water leaving the test separators for the following reasons:

a) The liquid leaving the separator is near to its bubble point. Even when 10 metres of liquid head are created between the separator and the flow meter any pressure drop downstream of the flow meter would result in gas breakout, the effectively rules out an in-situ proving device associated with turbine meters.

b) Mass flow measurement using conventional turbine meters would require density meters for mass measurement. The proximity to the bubble point would make density measurement difficult without a pumped arrangement. The requirement for minimum facilities would make this additional equipment difficult to justify.

c) Total Oil Marine have used coriolis meters for Fiscal metering since 1989 and also for well testing purposes. During this period the coriolis meters (Micromotion D100) have proven to be reliable and to have excellent long term stability. This has been established through in-situ proving and recalibration tests at the factory. Thorough independent testing has also verified an insensitivity to the density and viscosity of oil / condensate / water used.

d) Coriolis meters measure both mass flow and the density of liquid passing through the meter. This allows actual volume to be calculated. Another benefit is that a measurement of oil / water emulsion density also allows water content to be derived providing the dry oil density and produced water density may be calculated at meter conditions.

e) There are no moving parts in a coriolis meter that can over-speed, wear or become damaged. No protection strainers are required upstream which would result in undesirable pressure drop providing erosion constraints are not exceeded.

In order to cover the range of liquid flows, coriolis meter sizes of 3", 1" and 1/2" were required. This was largely a result of the requirements for a working pressure of over 120 barg and a wetted part material of Hastelloy C due to the presence of chlorides in the produced water. The pressure drop limitation also restricted the upper flow limit of individual meters.

A rigorous test programme was undertaken to ensure the coriolis meters met the manufacturers claims for mass flow and density uncertainty on a range of fluids, temperatures and pressures chosen to represent the test separator conditions.

During the course of these tests, considerable difficulties were experienced with the original 3" meters. At the time of order placement these high pressure meters were the only type available to meet the pressure and material requirements. Testing indicated that the meters lacked structural rigidity and would only perform when solidly clamped to a high mass support structure. This could not be reproduced in service due to the need for pipework expansion under process temperature changes.

Replacement units in the form of 3" Micromotion 'Elite' meters became available which provided the required performance over a wider than anticipated flow range.

Temperature and pressure transmitters were mounted at the upstream meter manifold in order to provide measurements for density calculation and volume referral.

Digital communication with the coriolis meter transmitters gave mass flow rate and density values. Pressure and temperature values were again acquired digitally using HART protocol.

System Layout

A major consideration when planning the layout of the Dunbar platform was to ensure that sufficient pressure margins existed in the coriolis meters to prevent gas breakout. This is most likely to occur at maximum flowrate when static pressure at the meter will be lowered by pipe friction, fittings losses and meter pressure drop. The test separator was positioned as high in the platform process area as possible while the coriolis meters were positioned on a lower deck to generate the maximum available liquid head in order to avoid gas break out in the meters. Any check meters or proving device could not be positioned downstream as gas breakout would occur at these points.

The position of the existing two test separators on Alwyn North could not be changed. The new coriolis meters were positioned to generate the maximum available liquid head. This resulted in new pipes being run down through additional deck levels to the new meters.

Well Test Computer System

In the past, well test reports have been generated by a supervisory computer (SVC) on Alwyn North with meter data provided by the Process Control System (PCS). The supervisory computer was coming to the end of its useful life and a replacement was planned. However, it became clear that the replacement SVC could not be procured to include the well test functions required to the Dunbar project timescale. It was also determined that front end flow calculations could not be performed in the Process Control System to the degree of measurement uncertainty required.

A standard Fiscal metering approach was adopted in that computer functions were split into a stream computer plus database architecture. Field measurements of the following parameters are transmitted digitally into the stream computers (see Fig. 7).

Gas	:	Differential pressure Absolute pressure Downstream temperature
Wet Oil	:	Emulsion mass flow rate Emulsion density Temperature Pressure
Oily Water	:	Emulsion mass flow rate Emulsion density Temperature Pressure

Each gas stream computer calculates mass, actual volume and standard volume flowrate using a gas composition specific to the well under test. Each liquid stream computer calculates the flow for two meter runs. The mass, actual volume and standard volume flow rate of dry oil and produced water passing through each meter is calculated in the following manner:

The dry oil density at meter temperature and pressure is calculated using standard API equations and oil properties of the well under test. Produced water density at meter temperature and pressure is calculated from an equation fitted to data variables of salinity, temperature and pressure. The water salinity of the well under test is used.

The following equation is used to calculate the mass % water in the oil / water mixture passing through the coriolis meter:

$$\text{mass \% water} = \frac{\rho\ \text{water}.\ \rho\ \text{em} - \rho\ \text{water}.\ \rho\ \text{oil}}{\rho\ \text{water}.\ \rho\ \text{em} - \rho\ \text{em}.\ \rho\ \text{oil}} \times 100$$

where ρ em = coriolis meter measured emulsion density
ρ oil = calculated density of dry oil at meter conditions
ρ water = calculated density of produced water at meter conditions

This result may then be used to calculate the mass flow rate of dry oil and mass flow rate of produced water flowing through the coriolis meter.

A similar approach is used to calculate the oil and water actual volume and standard volume flow rate.

All flow computer constants are held in the database computer and may be updated under appropriate security protection.

Each well has its own set of parameters such as gas composition, isentropic exponent, dynamic viscosity and gas expansion coefficient. The liquid properties of oil K0, K1, oil standard density, water standard density and water salinity are also held for each well. Once a well is lined up to the test separator a command is sent from the Process Control System and the appropriate constants for the well under test are automatically downloaded to the flow computers. In this way flow calculations are performed with the minimum of uncertainty.

The database computer sums gas, dry oil and produced water flow rates from the stream computers to form a total well oil, water and gas mass flow rate for allocation purposes. This is repeated for actual volume and standard volume flow rates for reservoir management purposes.

Once the well flow has stabilised the well test recording may commence and cover a period of up to 12 hours. During each hourly period the average flow rates, temperatures and pressures are calculated, displayed and stored. A continuous period of 6 hours stable flow is required for a successful well test. The standard deviation of flow rate and pressure values are calculated from samples of instantaneous values during each hour. The standard deviation indicates the stability of measured / calculated parameters in order to determine which average flow rates are to be selected to form the final average.

Dunbar has one well test system for the Alwyn South test separator, three gas meters and six liquid meters are interfaced to the computer system. Alwyn North also has one well test system but this serves two test separators, although the combined number of flow meters is similar to Dunbar at two gas and six liquid.

A compromise was necessary with the number of well test points due to the large amount of wells to be tested on a monthly basis. It was agreed that two well test points would be sufficient to describe the relationship between well head flowing pressure and well flow rate providing one test point would be close to the normal operating well head flowing pressure.

Computer Network

Two new computer systems have been installed in order to acquire data and then to process it in accordance with commercial procedures.

Data is acquired by the Networked Information Management System (NIMS) which has effectively replaced the SVC on Alwyn North. NIMS is interfaced to both well test computers, Alwyn North and Dunbar process control systems plus the two export metering systems. Data such as well tests are automatically transferred to NIMS where they are examined and validated prior to transfer to the Hydrocarbon Accounting System (HAS) computer located onshore. This operation ensures that as much data as possible is captured automatically but that only authorised data is used in the allocation. Well tests may then be linked in order to allow interpolation of well flow rate from well head flowing pressure (see Fig. 8).

An important feature of the well test information is that raw data such as gas differential pressure is transferred with calculated flow rates. This allows flow rates to be recalculated once more representative analysis data becomes available. The well test is always performed with the previous months analysis.

The daily average process data acquired by NIMS is used by HAS to perform the process simulation in order to determine representative allocation coefficients. Metered export and fuel / flare quantities are then allocated to each production manifold and then to each well. The Alwyn Area sub-allocation is run daily in order to determine well and field production (see Fig. 9).

Coriolis Meter Zeroing

An important part in the operation of coriolis meters is to establish a representative zero. The meter will not perform to its normal specification with a significant zero instability or offset.

For optimum operation it was decided to check the zero of the in use meters prior to each well test. This involves bringing the meter up to operating pressure and temperature, ensuring there is no vapour present and then closing the meter outlet valve with flow redirected. The unmasked flow rate should be zero ± the manufacturers zero instability, if this is not the case the meter should be rezeroed.

On Dunbar this operation could impose a significant workload on the technician responsible due to the distance between meter valving (operated manually) and panel mounted flow transmitter.

A remote zeroing facility was adopted which allows the technician to remain in the process area while the meter is being automatically checked for a correct zero and then automatically rezeroed if necessary.

In order to perform this function the well test computer system recognises when a meter is brought on-line and then closed in. Once a field mounted push button is hit by the technician the computer system checks the unmasked flow rate measured by the coriolis meter against set tolerances. If the zero flow is within tolerance the technician receives a green light and can place the meter online. Otherwise there is a delay while the meter is automatically rezeroed prior to the Technician being ok'd to place the meter on-line. The measured zero instability and time of any rezeroing are displayed and printed.

Sampling

Three distinct types of samples are required to be taken, analysed and reported to the Hydrocarbon Accounting System (HAS).

a) Gas composition to C7+ for gas density calculation purposes (each well test pair).

b) Water in wet oil and oil in oily water to amend liquid effluent flow rates (each well test).

c) Liquid and gas detailed composition to C11+ to determine well compositions (performed on each well every six months).

The minimum facilities philosophy for Dunbar dictated that manual sampling was performed in preference to automatic sampling.

Sampling points on Dunbar and Alwyn North test separator outlets were installed to a similar standard. These points featured sample probes in well mixed areas, facilities to purge the sample line to flare or closed drain in a controlled manner and to capture a representative sample in a safe manner.

The detailed compositions to C11+ are analysed onshore from high pressure gas and liquid sample cylinders.

The remaining analyses are performed offshore in local laboratories to standard procedures.

HAS combines the detailed compositional analysis with the corresponding well test flow rates to arrive at the well composition.

The analysed level of contaminants in wet oil and oily water are compared in HAS to the online calculated values and the most representative value selected. It is planned that the on line calculated valves may be tuned to allow sampling and analysis of contaminants to cease, thus reducing operating costs.

System Commissioning

Thorough testing was performed at each stage of procurement of the new well test systems and computer systems. Wherever possible tests were performed to check the interface from one system to another to ensure reliable communication.

The new Alwyn North systems were installed some months prior to the Dunbar start-up with the minimum of disruption to the running of the platform. Commissioning the Alwyn North systems well in advance of Dunbar start up and using them for well testing purposes and trial allocation gave time for debugging and improving procedures prior to the date of full implementation.

Commissioning of the Alwyn North well test system proceeded without any major problems. However, it was considered that the zero instability of the coriolis meters was too high.

Detailed investigations with the assistance of Rosemount revealed that the meter drive voltage was varying more than normal. Drive voltage can be measured at the panel mounted flow transmitter and is an excellent indicator of the 'health' of the meter. A variable voltage shows that the meter is not fully 'locked on' to the mass flow rate and density values. A saturated value shows that the meter has lost control of flow and density measurement, usually as a result of severe vapour entrainment or slug flow. Causes of the instability were considered to be electrical interference, lack of rigidity in the meter supports or possible vibration crosstalk with parallel meters. Electrical connections and cable type and routing between the flow sensor and flow transmitter were found to be correct but there were some unnecessary lengths of unscreened cable at the panel terminal blocks. This was resolved but did remove the instability.

Attention was focused on the meter supports and any lack of rigidity that would result in the meter drive being used to vibrate the surrounding pipework. It is vital for successful operation that the meter body is clamped firmly to a solid base in order that only the flow tubes are vibrated with the minimum amount of drive necessary. The manufacturer recommended arrangement is shown in Fig. 10.

The meter supports in use had been designed to accommodate pipe expansion due to process temperature changes. A sliding joint was used on one support to allow pipe movement, both supports used 'I' section mounts. This combination resulted in an unsufficiently rigid system.

The supports were modified by fitting polyurethane "Stauff" clamps on either side of the meters. This modification improved the zero stability of the meters and gave a less variable drive voltage. It also allowed for temperature expansion. The question of vibrational crosstalk between parallel meters was examined by turning off the power to one meter while monitoring the output of the other meter, no change was observed. This indicated that there was not a significant level of crosstalk present.

Another area examined was how the density derived values of water in wet oil and oil in oily water compare to sample / analysis values. At first there was a considerable difference but once detailed well compositions became available and new parameters calculated the discrepancies were reduced. However, the test separators in the Alwyn Area provide good separation and little contamination is found in the liquid flows. The density derived water cut is not reliable below approximately 2% water in oil and is not suitable for calculating the present ppm levels found by sampling / analysis. If poorer separation occurs it should be possible to replace sampling / analysis with density derived water in oil measurement and provide useful savings in operating costs.

System Performance

The well test metering system has performed reliably during its operation since Dunbar start up in December 1994. Regular calibration testing on the instrumentation has not identified any drift problems.

Figures 11, 12 & 13 show the deviation between well flow estimation and hydrocarbons allocated to a group of wells from Export oil and gas plus fuel and flare. Well flow is estimated from interpolations of well tests. The main points to note from the graphs are the similarities in trend across well groups, this indicates that allocation is being performed fairly. There is an improvement during the month as more well test data is gathered. The two upsets observed are due to production shutdowns which result in an imbalance between well production and export.

Figure 14 shows the difference between all well production estimated from well test interpolation and export / fuel / flare quantities. The majority of results lie within the estimated uncertainties with the exception of the upsets caused by shutdowns. Later months show trends similar to the end of March.

These results demonstrate that the forecast levels of uncertainty have been achieved. Furthermore, the investment in a high standard of well test equipment and careful modelling of the processing of well fluid through the Alwyn North plant to export points has reduced any systematic uncertainties to an acceptable level. In addition to a fair allocation of production within the Alwyn Area the improved quality of data has provided improvements in reservoir management.

Conclusions

The development of the Alwyn South fields imposed tight economic and operational constraints on the method of metering field production.

The choice of a metering system based on the flow sampling technique has proven to be an important part of this successful marginal field development.

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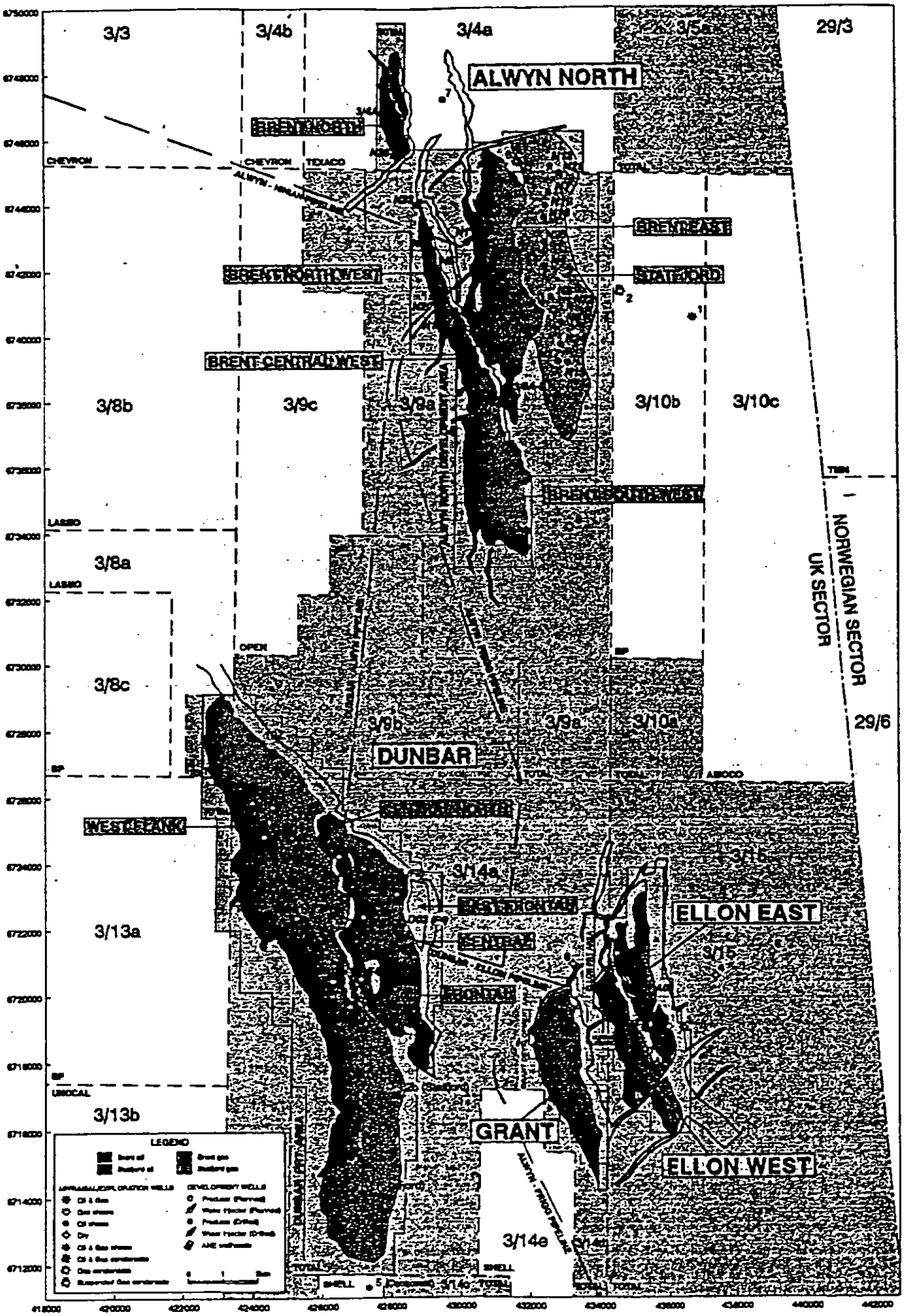
2) ISO 5167-1:1991 Measurement of fluid flow by means of pressure differential devices - Part 1: Orifice plates, nozzles and venturi tubes inserted in circular cross-section conduits running full.

3) ISO 6976:1983 Natural Gas - calculation of calorific value, density and relative density.

FIGURE 1

GREATER ALWYN AREA
Field Location Map



DP/PEP/AS/94/19JJ-MF

TOTAL OIL MARINE p.l.c.

MARCH 1994

FIGURE 2

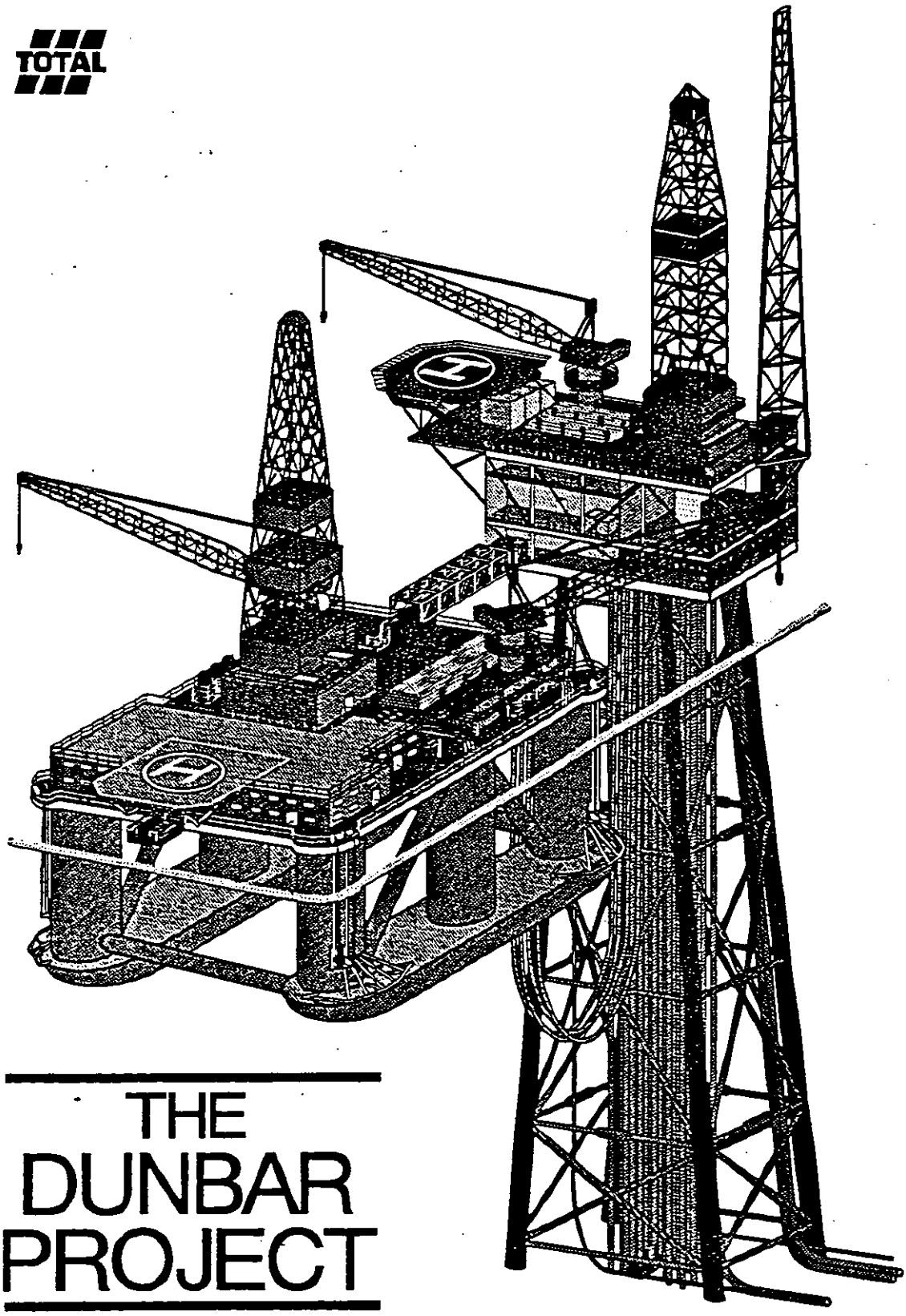


FIGURE 3

THE DUNBAR PROJECT (Phase 1) +
PROPOSED ADDITIONAL PHASES 2

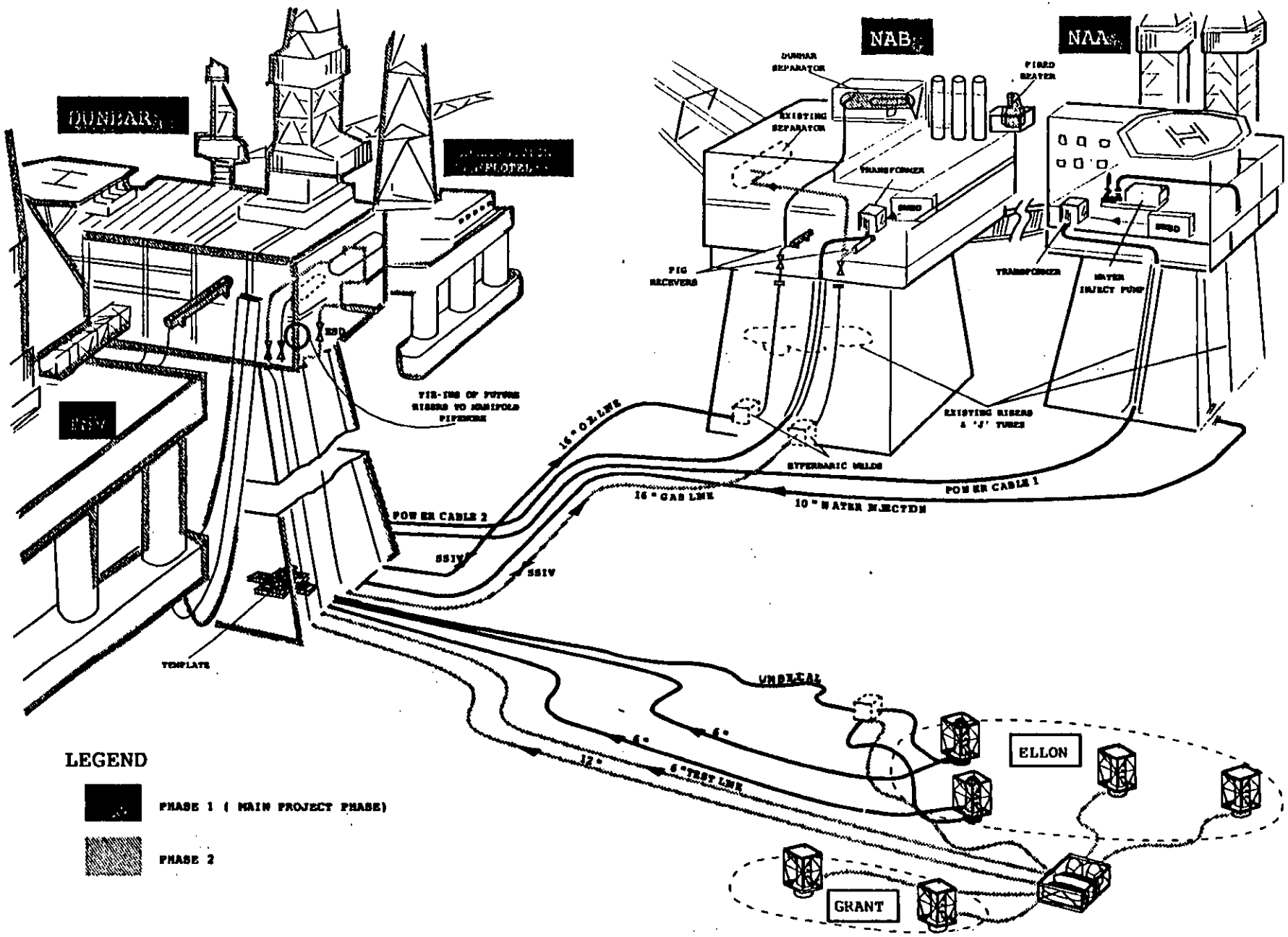


FIGURE 4

WELL MASS FLOWRATE CALCULATION FROM WELLTESTS

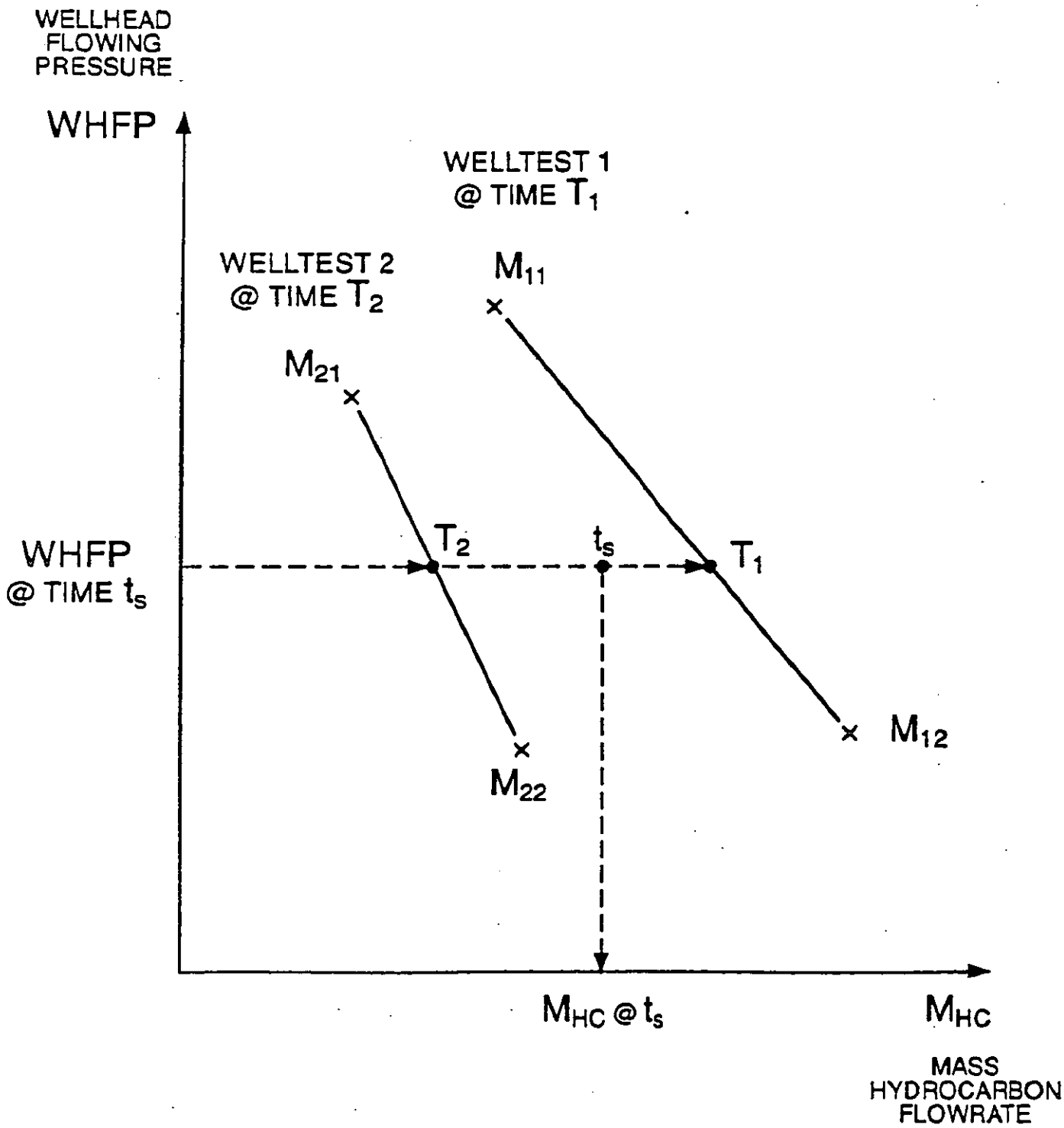


FIGURE 5

Alwyn Area Allocation Process Flow Diagram 1995

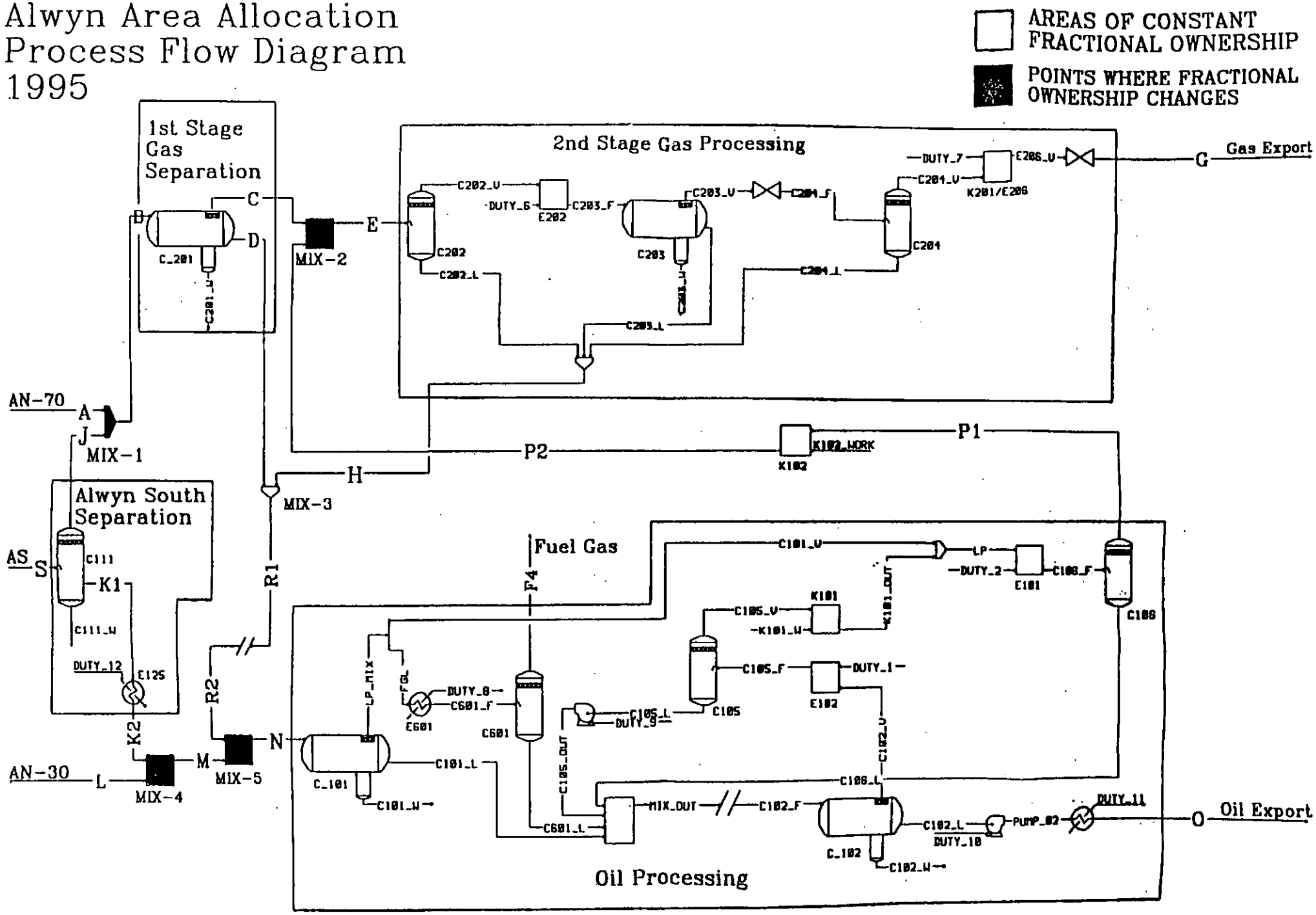
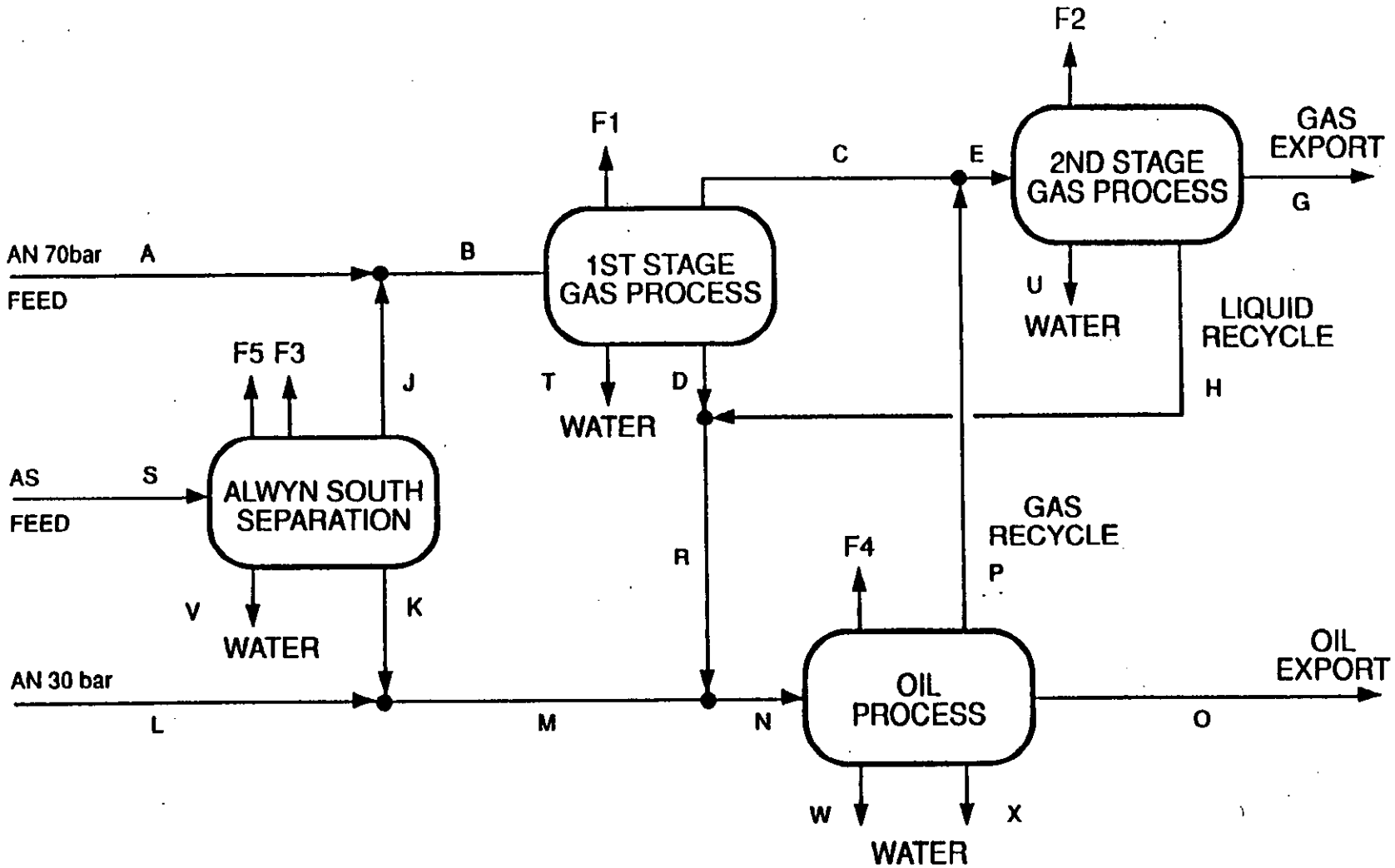


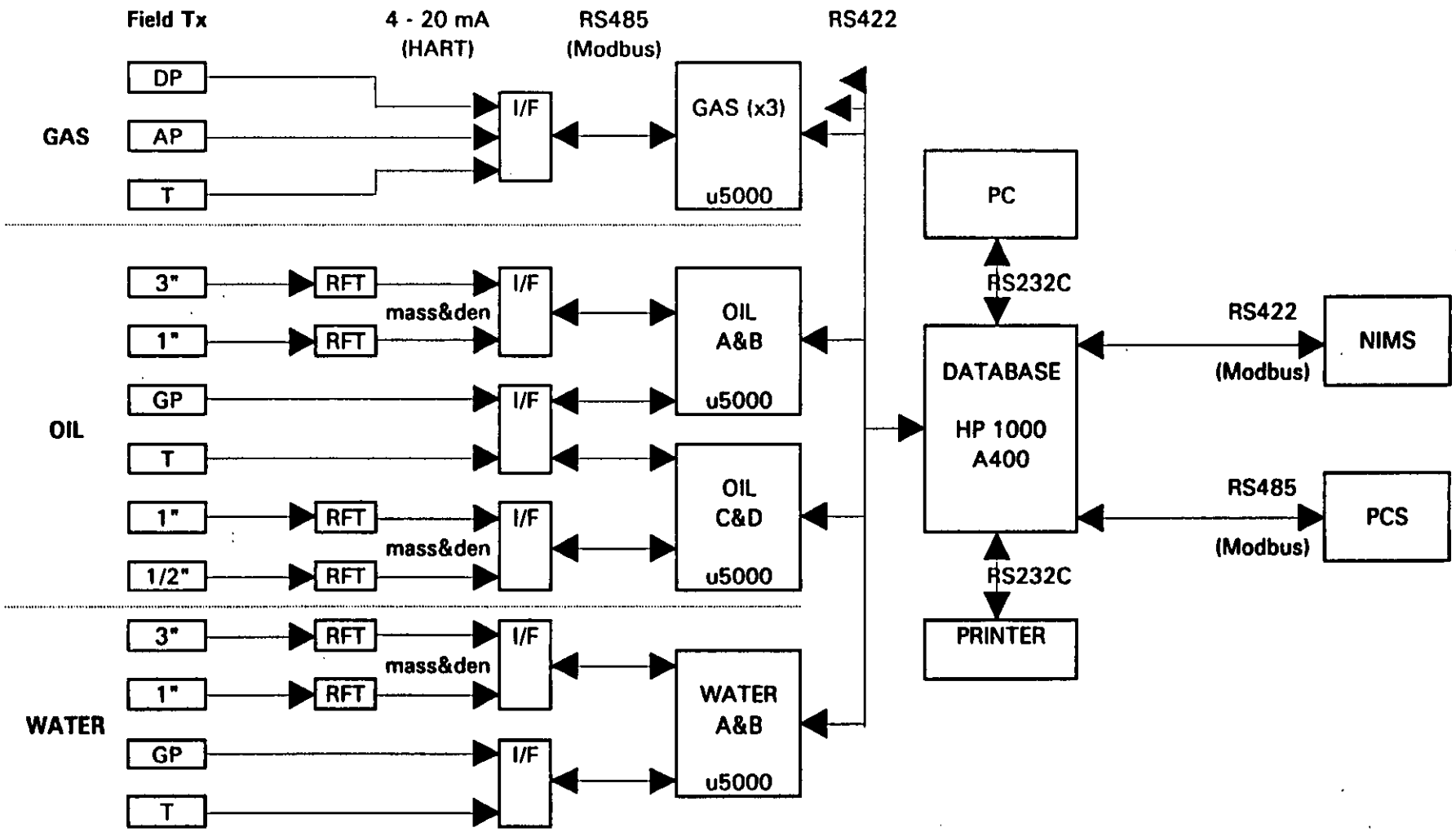
FIGURE 6

SIMPLIFIED ALWYN NORTH PROCESS SIMULATION



NOTE : Letters signify key streams used in the fractional ownership coefficients

FIGURE 7



DUNBAR WELL TEST SYSTEM ARCHITECTURE

FIGURE 8

DUNBAR WELL TEST COMPUTER INTERFACES AND DATA FLOW

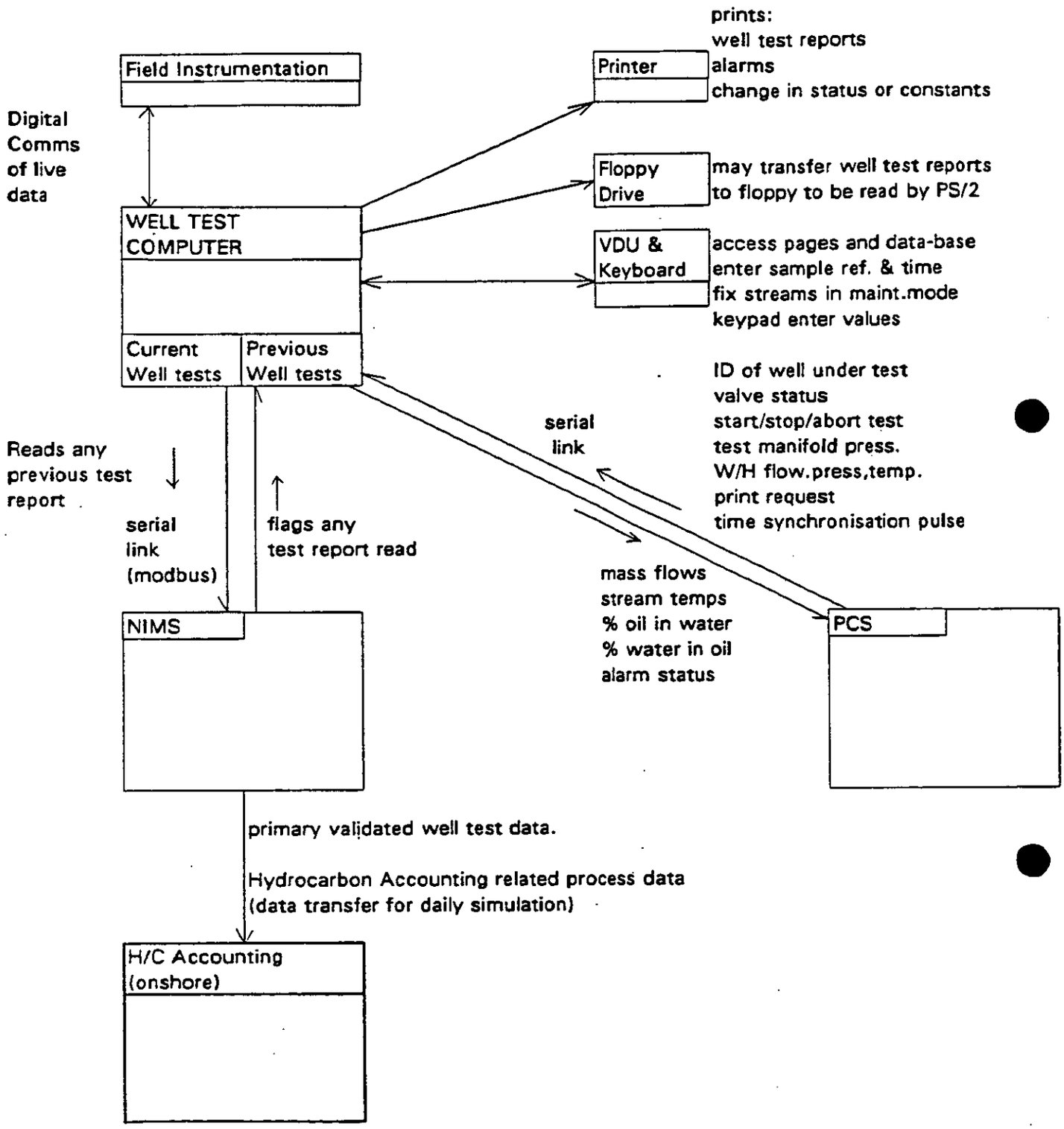
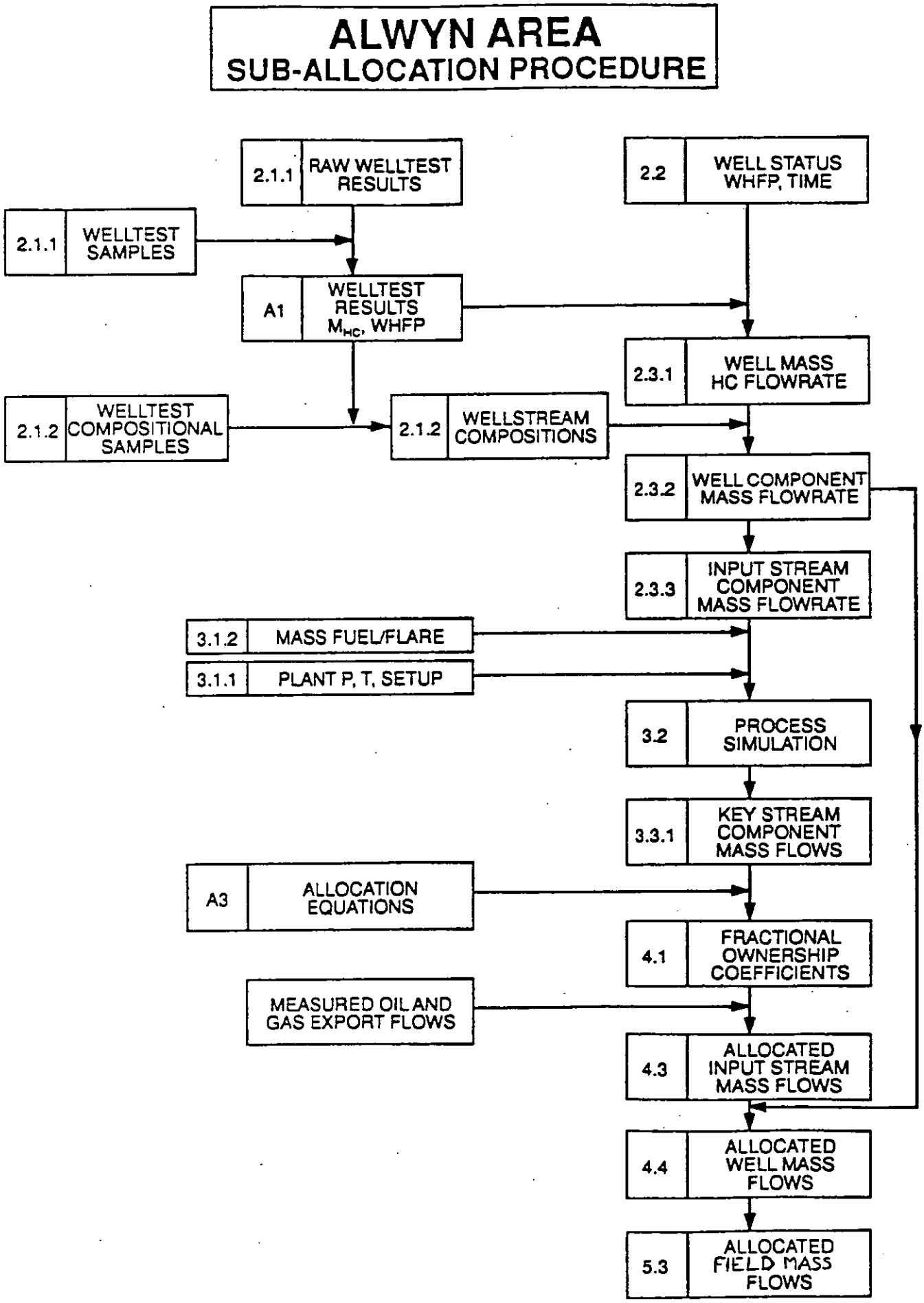


FIGURE 9


ALWYN AREA
SUB-ALLOCATION PROCEDURE
2.1.1 RAW WELLTEST RESULTS
2.2 WELL STATUS WHFP, TIME
2.1.1 WELLTEST SAMPLES
A1 WELLTEST RESULTS M_{HC}, WHFP
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A3 ALLOCATION EQUATIONS
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FIGURE 10

Typical Installation of an ELITE™ Sensor

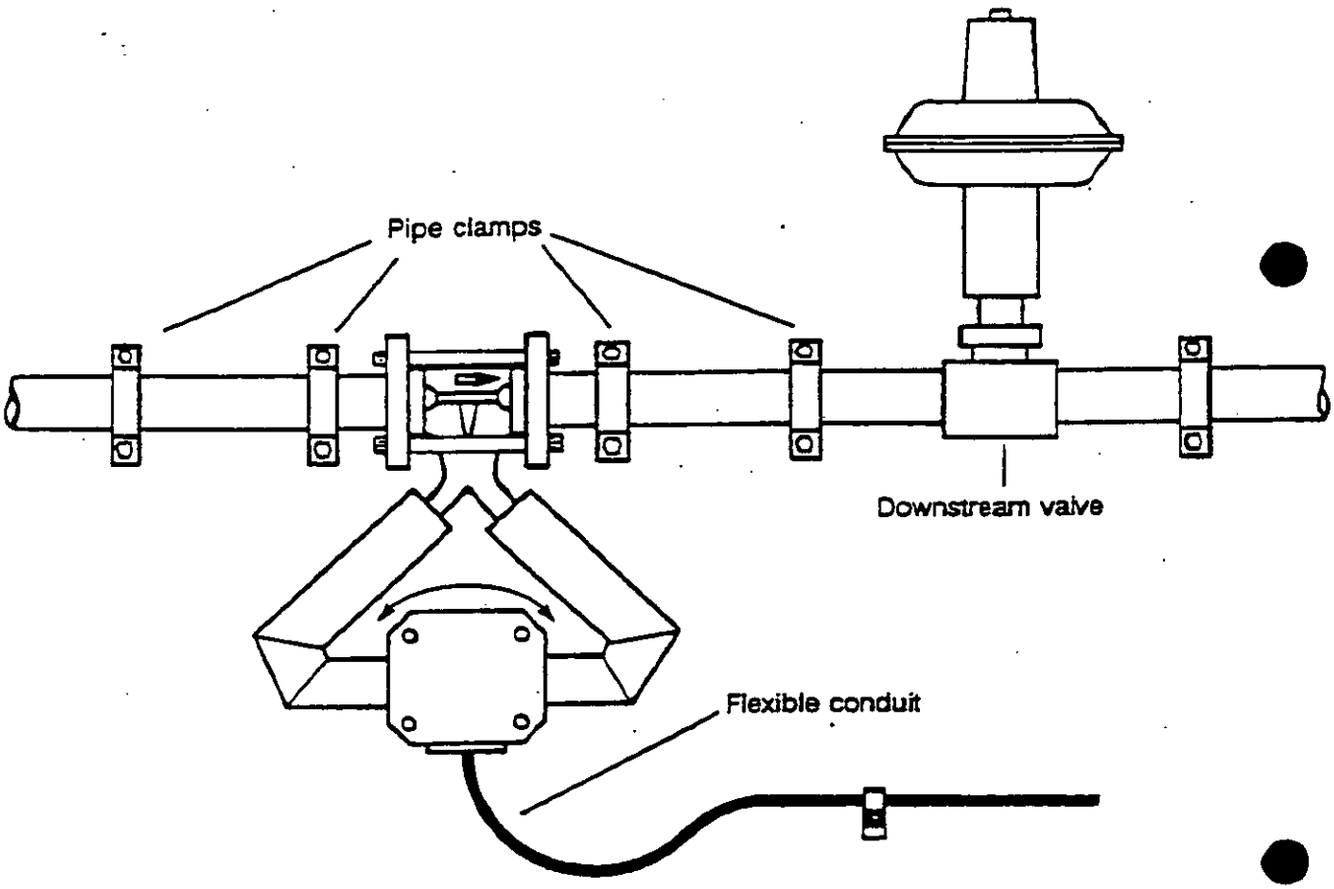


FIGURE 11

Estimated compared to Allocated Hydrocarbon Mass Flow

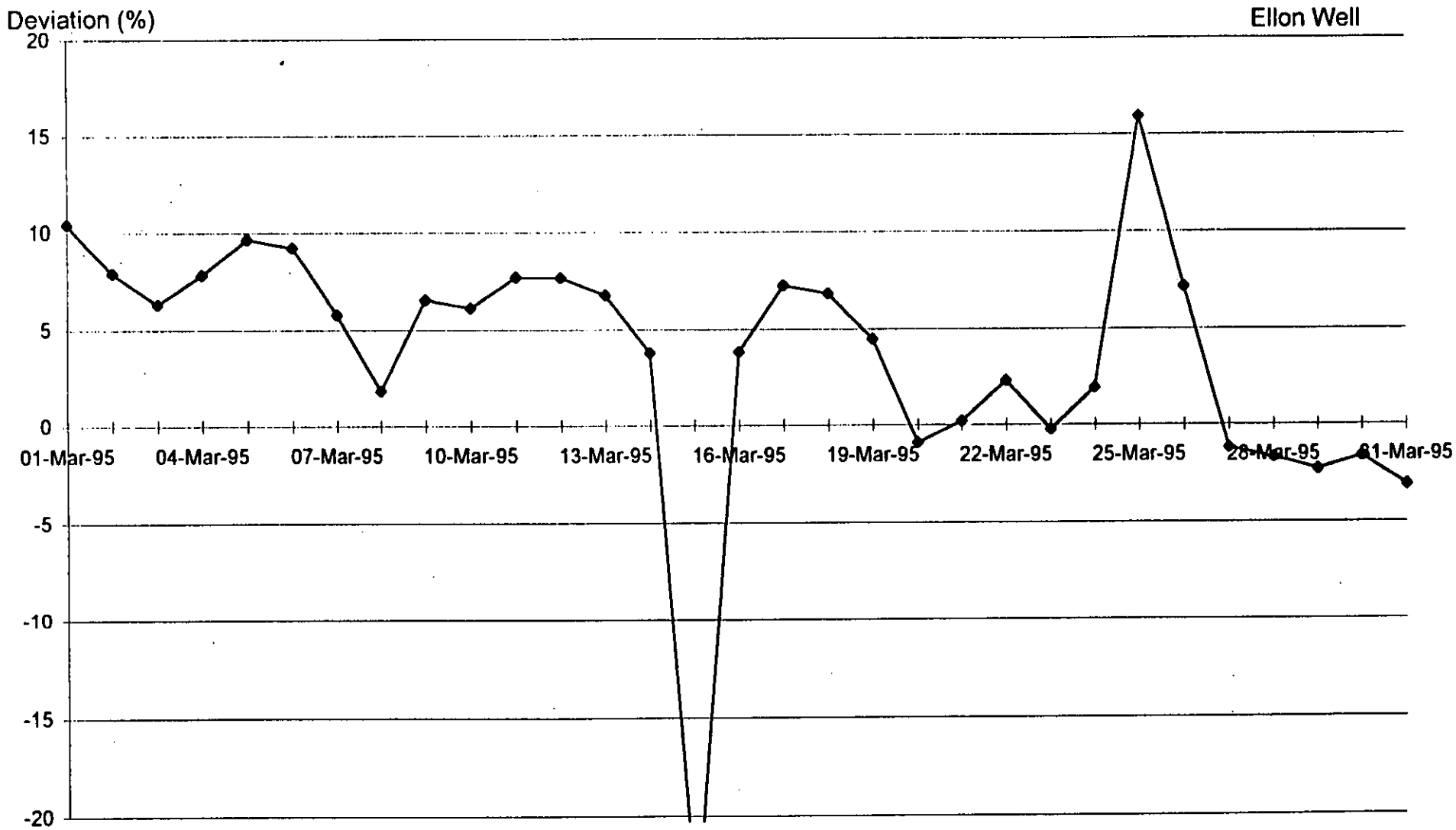


FIGURE 12

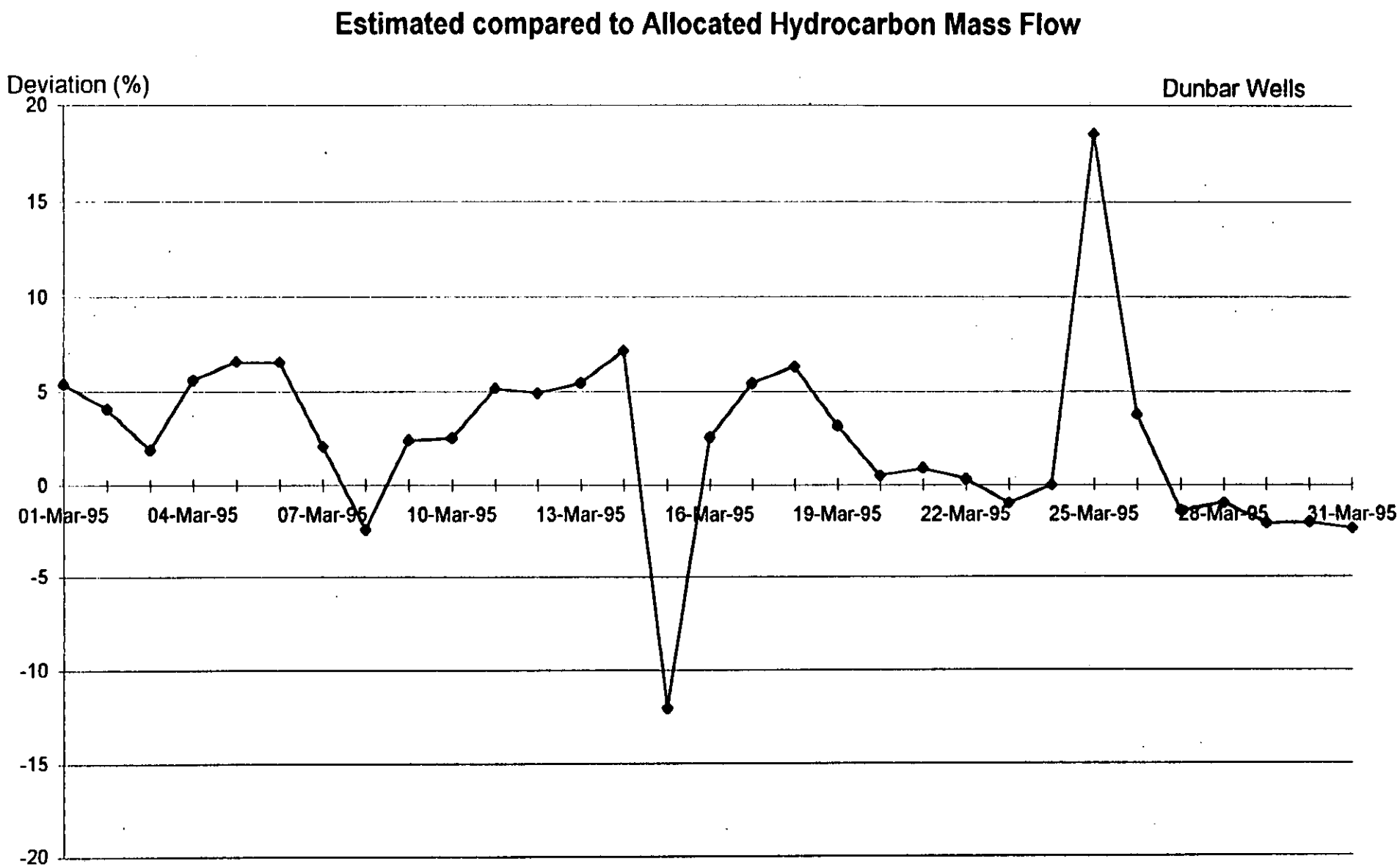

Estimated compared to Allocated Hydrocarbon Mass Flow
Deviation (%)
Dunbar Wells
20
15
10
5
0
-5
-10
-15
-20
01-Mar-95
04-Mar-95
07-Mar-95
10-Mar-95
13-Mar-95
16-Mar-95
19-Mar-95
22-Mar-95
25-Mar-95
28-Mar-95
31-Mar-95

FIGURE 13

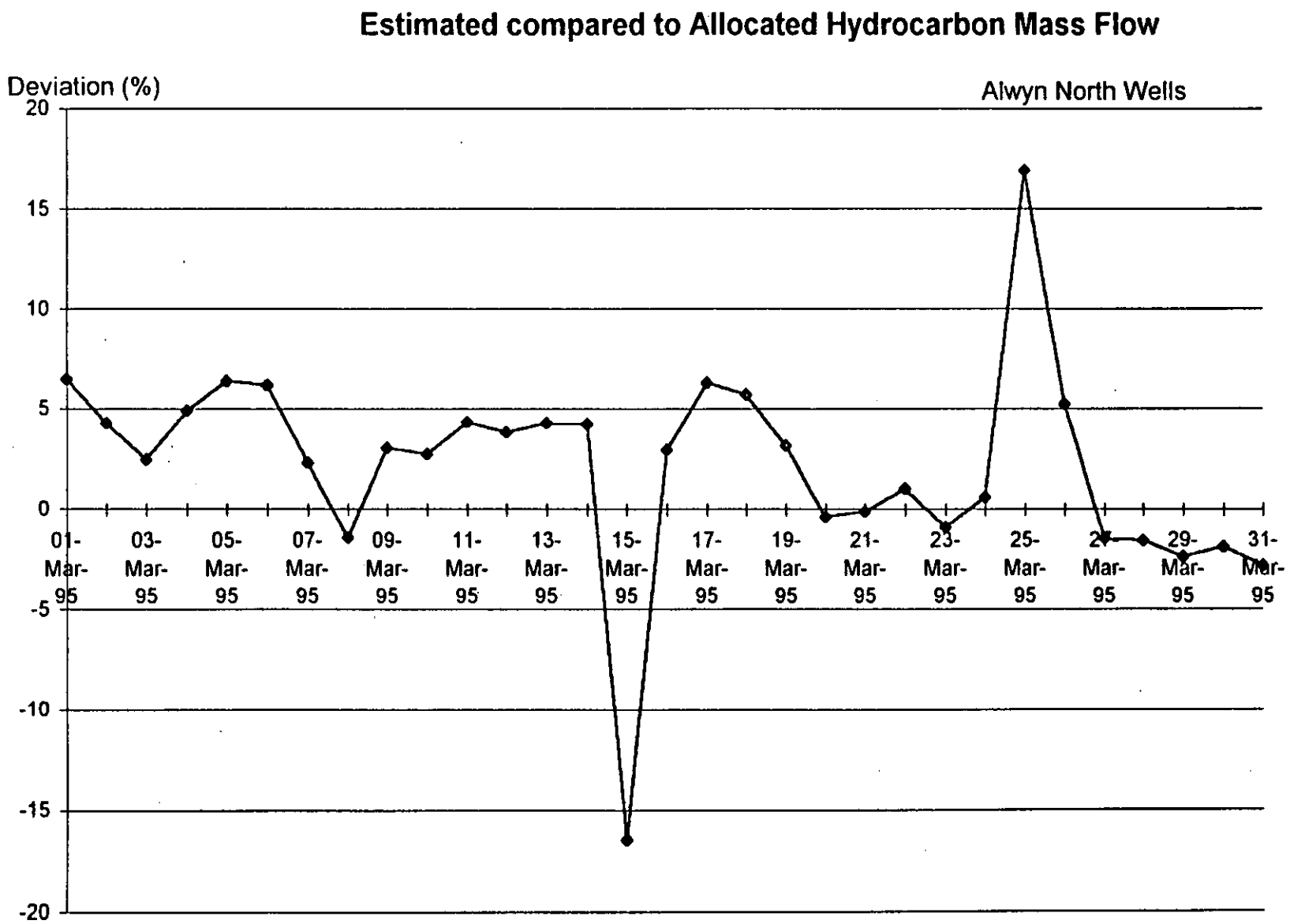
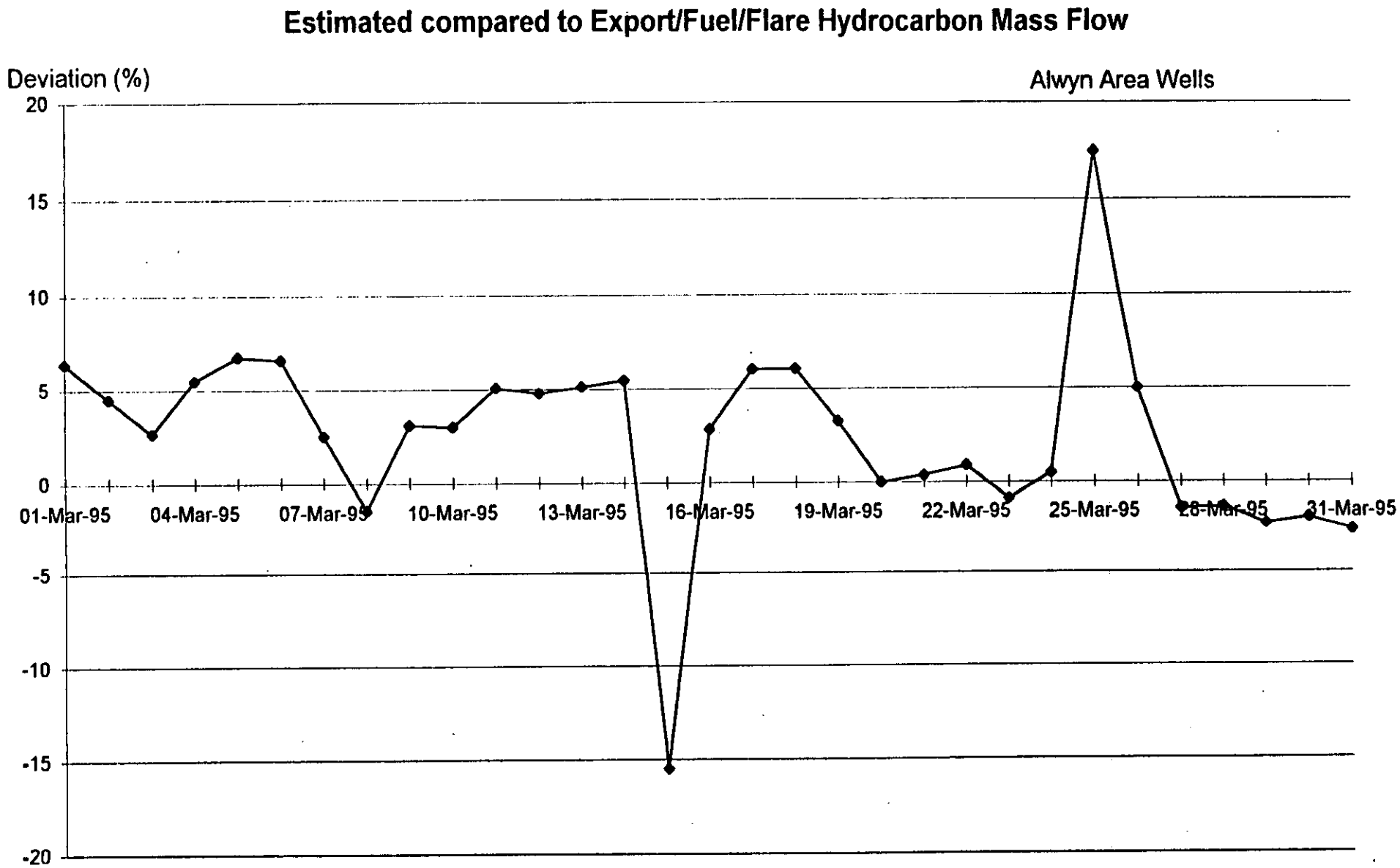

Estimated compared to Allocated Hydrocarbon Mass Flow
Deviation (%)
Alwyn North Wells
20
15
10
5
0
-5
-10
-15
-20
01-Mar-95
03-Mar-95
05-Mar-95
07-Mar-95
09-Mar-95
11-Mar-95
13-Mar-95
15-Mar-95
17-Mar-95
19-Mar-95
21-Mar-95
23-Mar-95
25-Mar-95
29-Mar-95
31-Mar-95

FIGURE 14


Estimated compared to Export/Fuel/Flare Hydrocarbon Mass Flow
Deviation (%)
Alwyn Area Wells
20
15
10
5
0
-5
-10
-15
-20
01-Mar-95
04-Mar-95
07-Mar-95
10-Mar-95
13-Mar-95
16-Mar-95
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31-Mar-95

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North Sea FLOW Measurement Workshop 1995

Paper 11:

THE EFFECT OF SWIRL ON CORIOLIS MASS FLOWMETERS

3.1

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Co-organiser:
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THE EFFECT OF SWIRL ON CORIOLIS MASS FLOWMETERS

Tim Patten
Micro Motion, Inc., USA

Dr. Gary Pawlas
Micro Motion, Inc., USA

ABSTRACT

Coriolis mass flowmeters provide accurate mass flow measurement over a wide range of flow conditions. A preliminary investigation of a Micro Motion CMF200 (50 mm) meter was performed to assess the accuracy over a range of sensor inlet configurations. Various inlet configurations were tested, including: straight run, a single 90° long radius elbow, and two out-of-plane 90° long radius elbows. Testing was performed with water under each inlet condition from 0.76 kg/s (100 lbs_m/min) to 7.6 kg/s (1000 lbs_m/min), which corresponded to a Reynolds number range of 36,000 to 360,000.

The meter factor was established on water during the first calibration; subsequent testing was conducted with the same factor. The maximum average bias error over the range of inlet conditions and Reynolds numbers was 0.03%, indicating the meter was largely insensitive to inlet flow profiles.

TEST SETUP

Five data runs were performed on a CMF200 meter from 0.76 kg/s (100 lbs_m/min) to 7.6 kg/s (1000 lbs_m/min)[1]. The meter factor was established at 3.8 kg/s (500 lbs_m/min) on water[2] during test #1 (Figure 1). Each of the five data runs consisted of points spaced in 10% increments between 0.76 kg/s and 7.6 kg/s. A range of inlet conditions was tested with hot water at the following conditions:

Temperature = 50° C
Pressure = 5 bar
$\mu = 0.5$ cp
$\rho = 988$ kg/m^3

Table 1 shows a tabulation of the tests; Figure 1 shows the inlet configurations tested.

Table 1 – Test Matrix

Test No.	Reynolds Number	Inlet Configuration	Inlet Configuration Figure Number
1	36,000 to 360,000	Straight	1a
2	36,000 to 360,000	Single Elbow	1b
3	36,000 to 360,000	Double Elbow	1c
4	36,000 to 360,000	Single Elbow	1d
5	36,000 to 360,000	Double Elbow	1e

[1] The maximum mass flow was limited by the calibration facility – the maximum mass flow rate for the CMF200 is 12 kg/s (1600 lbs/min).

[2] Note: All data was collected digitally – IEEE488 and RS485. Errors were assessed based on these data.

Three basic inlet configurations were tested:

1) Straight run -- A 300 mm straight run of 2" pipe (6 diameters) was provided immediately upstream of the sensing element
2) Single 90° long radius elbow upstream of the 300 mm straight run
3) Two 90° elbows out-of-plane upstream of the 300 mm straight run

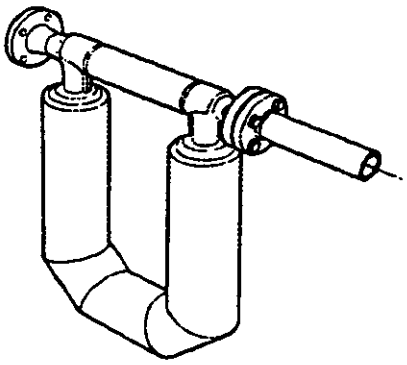

Figure 1a – Straight Inlet

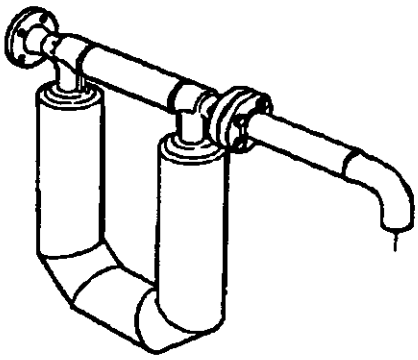

Figure 1b – Single 90° Elbow Parallel to Sensor Tube Plane

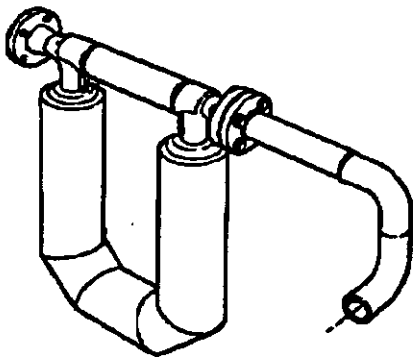

Figure 1c – Double Elbow. Elbow Closest to Sensor Parallel to Sensor Tube Plane.

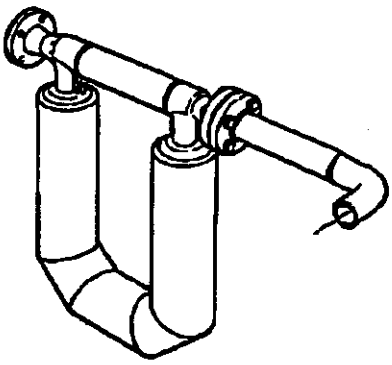

Figure 1d – Single 90° Elbow Perpendicular to Sensor Tube Plane

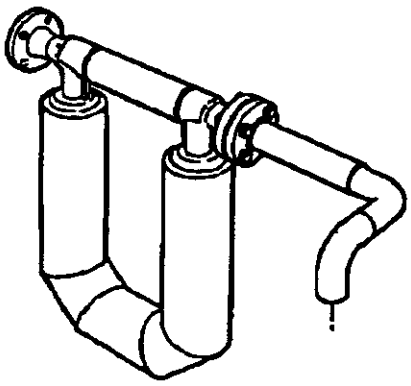

Figure 1e – Double Elbow. Elbow Closest to Sensor Perpendicular to Sensor Tube Plane.

In addition to the three basic inlet arrangements, it was theorized that the orientation of a 90° elbow next to the sensing element could have an affect on accuracy. Two additional tests were run to investigate the effect of the orientation of the 90° elbow next to the sensor. A total of five inlet configurations was tested, as shown in Figures 1 (a through e).

TEST RESULTS

Table 2 shows the average error from each calibration, corresponding to the conditions of Table 1 and Figure 1. Figure 2 shows each of the data runs, plotted versus Reynolds number. Figure 3 shows error versus mass flow rate.

Table 2 – Average Errors from Each Calibration

	Average Mass Flow Rate Error, %
1	+0.005%
2	+0.019%
3	+0.011%
4	+0.002%
5	+0.027%

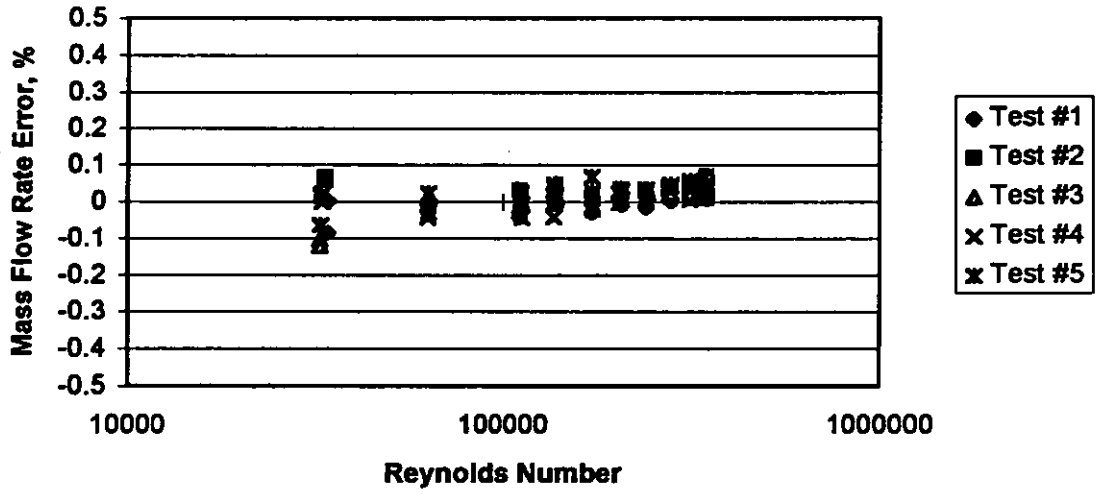

Figure 2 – Flow Rate Error vs. Reynolds Number for Each Inlet Configuration

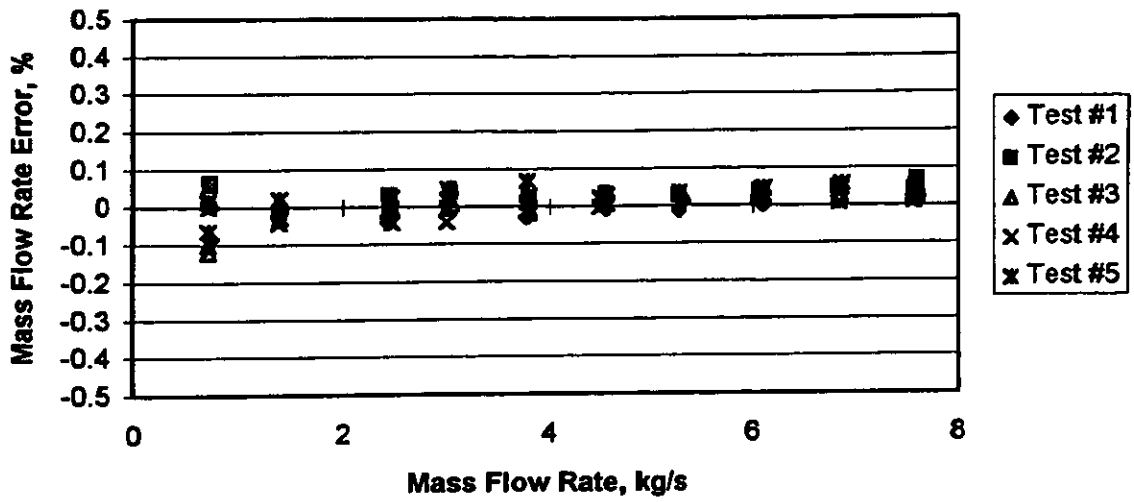

Figure 3 – Mass Flow Rate Error versus Mass Flow Rate

As can be seen, the effect of inlet configuration and swirl is very small over the 10:1 Reynolds number range. There is a slight non-linearity apparent at higher rates (less than 0.1%), and the effect of the zero can be seen at the 10:1 turndown point. However, these are typical Coriolis meter performance parameters; there is minimal additional effect due to the inlet configuration or swirl.

CONCLUSIONS

Coriolis flowmeters provide an accurate mass flow measurement over a wide range of inlet conditions. Testing at Micro Motion in Boulder, Colorado with water showed an average bias of only 0.03% among five different inlet configurations. Reynolds number varied from 36,000 to 360,000.

Additional testing needs to be performed to assess the effect of Reynolds number, especially below 30,000. Recent testing on gas suggests that there is little bias between water calibration and gas calibration (which are very high Reynolds numbers), at least within the measurement accuracy of the testing facilities. Additionally, liquid applications at higher Reynolds numbers will be limited due to pressure drop considerations.

This testing was performed under the described inlet conditions because it was felt they represented a relatively severe condition. Since little effect was determined, different configurations need to be addressed, especially shorter straight runs ahead of the sensor and short radius elbows.

Finally, the results presented here are based on the results of a single meter. Multiple meters of a common size need to be tested (50 mm size in this case), and Coriolis meters of different sizes and geometries need to be investigated.

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North Sea FLOW Measurement Workshop 1995

Paper 12:

PERFORMANCE OF CLAMP ON ULTRASONIC FLOWMETER PIPELINE LEAK DETECTION SYSTEMS

3·2

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PERFORMANCE OF CLAMP-ON ULTRASONIC FLOWMETER PIPELINE LEAK DETECTION SYSTEMS

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1. INTRODUCTION

Recent enhanced awareness of the environmental, safety and financial consequences of the release of petroleum and derivative petroleum products from pipelines, has made development of an effective and readily implementable pipeline leak detection system essential. It is not surprising that the pipeline industry's first attempt to implement leak detection was based on software systems, using data from meters already installed in existing pipelines. However, considering that these conventional intrusive meters were usually specified for purposes other than leak detection, in these cases the performance obtained falls short of the level needed to protect both the environment and the financial interests of the industry.

Accordingly, there is an incentive for instrument manufacturers to create, and the industry to actively consider, new types of leak detection systems that are more effective in performance, and more affordable in cost. It is essential that the meters on which these systems are based provide the short term calibration stability required for fast detection of leaks, as well as the long term stability normally required over the time period of complete batches, as required for custody transfer. In addition, they must be logistically compatible with the reality that leak detection systems must be installed on a vast network of already existing pipelines, without requiring the pipelines to shut down operation for leak detector installation. Perhaps as important, the preferred leak detection system will not demand that pipeline operators change their normal operating procedures.

Fortunately, the modern clamp-on transit-time ultrasonic flowmeter meets the criteria for such a leak detection system in every way, as is detailed in the body of this paper. In addition, this type of meter is not new to the industry, having been in pipeline service for the petroleum industry in various forms for almost 20 years.

However, the key to the improved performance of the clamp-on transit-time meter in leak detection service is its ability to continuously identify the type and condition of the liquid in the pipeline, and thereby assure the correct calibration of the system at all times. This is important since it is well known that the liquid characteristics of crude oils can vary substantially, not only from batch to batch, but also even within each batch. This 'dynamic calibration' overcomes the short term variation of conventional turbine and PD meters, whose calibration is established only periodically by proving runs conducted only for a small percentage of each batch. In other words, these meters 'see' as to provings, only part of each batch, if provings are conducted for each one.

Use of these detected liquid properties is not limited to aiding leak detection performance. Sensing these properties also permits the transit-time leak detection system to provide interface detection, batch tracking, and liquid quality monitoring. Therefore the transit-time flowmeter-based leak detection system can pay back its cost through its ability to provide improved efficiency of pipeline operations and replacement of maintenance prone intrusive meters.

The basis for the benefits of the transit-time leak detection system lie in the performance and operating parameters of the ultrasonic meter itself. Since there are substantial differences in the design and performance of transit-time ultrasonic meters produced by different manufacturers, the user should examine the characteristics of the selected system's flowmeter to ensure that it includes:

1) Intrinsically high accuracy
2) Stable calibration over a wide range of liquid conditions
3) High flow detection sensitivity, even at zero flow
4) High flow rangeability and linearity, including bi-directionality
5) High reliability, requiring little or no maintenance
6) Installs easily without requiring shutdown of operations
7) Low installed cost, as compared to standard intrusive meters
8) Resistance to wear, or change of calibration through use
9) Fast response, able detect leaks in seconds
10) Capability of monitoring long pipeline segments
11) Ruggedness under actual site environmental conditions
12) Accuracy in multi-product pipelines
13) Detects and compensates for free gas
14) Empty pipe detection
15) Immune to corrosive or abrasive liquids
16) No pressure drop, to save pumping energy costs
17) Compatibility with many different types of nondescript liquids
18) Capable of installation near bends and elbows
19) Minimal operating power, for remote area operation
20) Has provision for optimizing calibration for actual site conditions

These characteristics are intrinsic to the clamp-on transit-time system, as described in the body of this paper, below, as presented follows:

- Principle of Operation
- Application Requirements
- Functions & Output Data
- Performance Parameters
- Installation Logistics
- Description of the Leak Detection System
- Performance of the Leak Detection System

2. PRINCIPLE OF OPERATION

The principle of operation of the clamp-on transit-time flowmeter is described in conjunction with Figure 1. Shown is the high precision system that uses the patented Wide Beam clamp-on transducer.

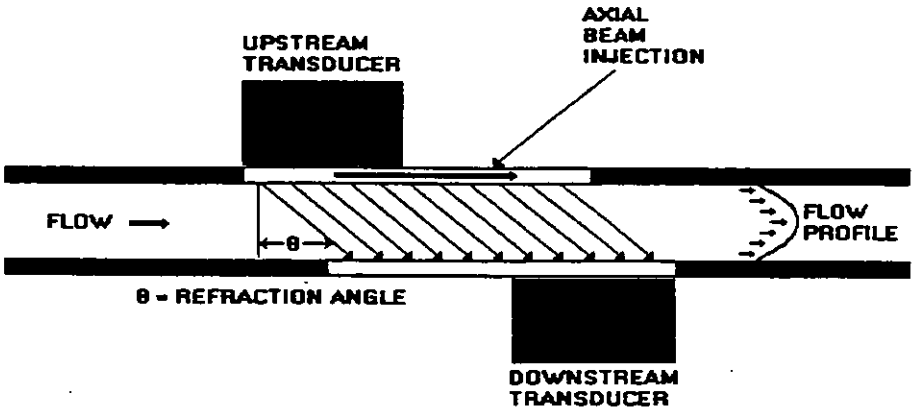

Figure 1: Wide Beam Transit-Time Principle

As shown, the Wide Beam transducer excites a natural *acoustic waveguide* mode of the pipe so as to induce a sonic wave which travels axially down the pipe wall. As it travels it *'rains'* sonic energy through the liquid in the form of a wide beam. This beam arrives at the far wall and travels down toward the receive transducer, where it is collected. Note that Figure 1 shows what is called 'Direct' transducer mounting. An alternate 'Reflect' mounting is available, in which both transducers are mounted on the same side of the pipe.

The advantage of the Wide Beam is that the angle of refraction of the beam is a function of the liquid sonic propagation velocity, which varies from about 600 meters per second for very light compressed gasses, to about 1500 meter per second for heavy crude oils. The wide beam assures that no matter what liquid is in the pipe, and what its refraction angle is, the beam will still *cover* the receive transducer and permit continuous operation of the system. In fact, this meter can operate on sequential batches of compressed gas, followed by oil, without requiring any human intervention or readjustment.

Sonic energy is injected alternately in the 'downstream' and 'upstream' directions. When sent upstream, the travel time required to reach the opposite transducer is longer than when sent downstream, proportional to the actual flow velocity. Thus the meter's ability to measure the flow rate is based on measurement of this time difference.

Note that the meter also measures the actual time required for the beam to travel across the pipe, and thus it can measure the actual sonic propagation velocity of the liquid. The sonic velocity of the liquid is a function of its density, and therefore the transit-time meter can identify then correlate to the API number of the liquid in the pipe at all times, with a resolution of 1 part in over 200,000. Since the meter takes approximately 1000 measurements per second, it is always aware of what liquid is in the pipe. It can therefore detect the interface between different batches of liquid, and can detect the presence of water in oil.

Since the presence of free gas 'scatters' the sonic beam to some degree, it affects the amplitude of the received sonic signal. This is very useful in that it permits the detection of 'Aeration' the term applied to the presence of free gas, whether included in the source product, or derived from depressurization or cavitation. A numeric value is assigned to the degree of aeration, which is reported as output data.

If a pipe empties, the sonic beam is completely interrupted. This loss of signal is monitored by the meter which issues an Empty Alarm if such a condition occurs.

3. APPLICATION REQUIREMENTS

3.1 PIPE & LIQUID SONIC PROPERTIES

The Clamp-on Transit-time Ultrasonic meter is among the most widely applicable of all flowmeter types. This is because the only thing that is required for operation is that the pipe wall be sonically conductive, and that the liquid also be sonically conductive. All common pipe materials are sonically conductive, as are all liquids.

3.2 STRAIGHT RUN REQUIREMENTS

Most flowmeters require installation with at least 10 diameters upstream, and 5 diameters downstream, straight run. In addition, some flowmeters require upstream straighteners to defeat swirl effects. While substantial straight run, and avoidance of swirl, are desirable for any flowmeter, in the pipeline industry accessible pipe is frequently of limited length, and often severely populated with bends and elbows.

Fortunately, where long straight runs are simply not available, mounting directly adjacent to bends and elbows is permitted for clamp-on transit-time flowmeter transducers. This is because the process of optimization reveals any calibration effects due to these conditions, and permits them to be counteracted at all flow rates, and for all liquids, even if of highly variable viscosity. This process also reduces the need for frequent proving, since the behavior of a given type of liquid is 'remembered' and the correct calibration is automatically installed. In addition, the fact that the transducers are clamp-on permits the installer to try several different locations, and simply select the one which shows the minimum evidence of flow profile distortion.

Where flow profile is severely aberrated due to nearby bends and elbows, or intrusive elements such as pumps and valves, it is recommended that a multi-path transducer installation be employed to average out the profile distortions. They are available in dual, triple or four path models. In general, dual path systems are sufficient for all but the most severely distorted profile conditions. In addition, the use of a transducer mount configuration where the transducers receive a reflection of the transmit signal (Reflect mode) completely eliminates any error due to non-axial flow. Swirl, other than its effect in flattening the flow profile, has absolutely no effect on clamp-on flowmeter calibration.

3.3 TRANSDUCER MOUNTING LOCATION ENVIRONMENT

Clamp-on transit-time transducers are available for any conceivable environment. They can be installed above or below ground, and can be installed under water. In addition, transducers of this type are capable of operation at very high and low temperatures, such as at 450°F in nuclear power plants, and as installed on the Trans-Alaska Pipeline.

3.4 VIBRATION

Clamp-on transit-time transducers are completely immune to vibration, other than the need to use the appropriate mounting accessory.

4. FUNCTIONS & OUTPUT DATA PROVIDED

Once per minute, clamp-on transit-time site stations provide the master station with the following data:

- Flow Rate (Average over the last minute for each path)
- Flow Total
- Liquid Temperature
- Ambient Temperature
- Liquid Sonic Properties:
  - Sonic Propagation Velocity, Vs
  - Sonic Signal Strength, Valc
  - Liquid Aeration, Vaer
- Timed-Stamped Maximum Rate of Change of Vs
- Site Station Diagnostic Data:
  - Empty Pipe Alarm
  - Flow Direction
  - Operation Fault
  - Aeration Alarm

In addition to providing data to the leak detector master station, each site station is capable of providing local site control, flow rate alarms and empty pipe alarms, etc.. The same data as is provided to the master station can be fed to the pipeline SCADA system in parallel. Output data is available in every standard data format, such as 4 to 20 mA, 0 to 10 Volts, and RS-232.

5. PERFORMANCE PARAMETERS

It is surprising to some that the performance parameters of the clamp-on transit-time meter are superior to those of the conventional intrusive flowmeters, since there is an intuitive 'feeling' that something that is in actual contact with the liquid 'must' be superior to a meter whose sensing is non-intrusive. However, when one considers that the intrusive meter calibration suffers from wear, coulomb and viscous friction, and residual flow profile distortion, it becomes fairly obvious that the intrusive meter derives its reputation for accuracy primarily from periodic proving, and prover repeatability.

When proving is done at least once for a batch of uniform product, and the flow rates and other conditions remain stable, the accuracy obtained for the total batch volume can be excellent. However, on many occasions, batches of product are not uniform, and flow rates and liquid temperatures can vary significantly. Under these conditions, unless proving is done frequently, the calibration factor obtained for infrequent proving will not provide accurate meter factors.

In addition, it is essential to recognize that periodic proving is quite adequate for custody transfer purposes. However, periodic proving of leak detection meters is not adequate. This is because the accuracy of a batch is determined on the scale of many hours or even days. The accuracy of a leak detection system must be maintained for periods as short as 1 minute, to assure detection of a leak in the fastest possible time, and to avoid false alarms which defeat operator confidence in the system. Periodic proving, no matter how precise at the time it is performed, cannot protect a conventional intrusive meter leak detection system from inaccuracy at the 1 and 5 minute interval level, since batches of product are frequently non-uniform, and physical constraints prevent such frequent cycling.

On the other hand, the clamp-on transit-time leak detection system identifies the product once per minute. Even a small batch non-uniformity cannot escape detection. And through the process of optimization, subsequently described in detail, the correct meter calibration factor is always provided.

The performance parameters and functions provided by the clamp-on transit-time site station include:

PERFORMANCE PARAMETERS	
Flow Range	From 0 to ±60 ft/sec flow velocity (bi-directional)
Flow Sensitivity	0.001 ft/sec at any flow rate, including zero
Liquid & Ambient Temperature Accuracy	0.1 °F
Calibration Repeatability	0.02 to 0.1%
Reynold's Number	From 1 to 10^9
Flow Change Bandwidth	10 Hz
Flow Slew Rate	80 ft/sec^2
Temperature Rating	- Flow Computer from -40° to +155°F - Transducers from - 80° to +450°F
Safety Ratings	Class 1, Div 1 & Div 2; NEMA 4X & NEMA 7
Site Station Power Requirement	15 watts
Interface Detection Resolution	1 part in 200,000
FUNCTIONS	
■ Built-in Datalogger with Site Identification and Time Stamp ■ 9600 Baud, RS-232 I/O Serial Data Communication ■ Built-in Diagnostics alerts user to liquid/system conditions ■ Built-in Pig detection	

6. INSTALLATION LOGISTICS

Installation of a clamp-on transit-time flowmeter is quite simple, taking from 1/2 to 1 1/2 hours. It generally follows the procedure below:

a) Installation site selection based on site survey, with a portable clamp-on transit-time flowmeter to check actual flow characteristics of several candidate transducer locations, or from site drawings, a particular location is selected. The preferences will be for as much straight run as convenient, in combination with avoidance of location immediately downstream of cavitation sources.

b) Identify pipe outer diameter, material and wall thickness

c) Install mounting tracks plus flow and temperature transducers.

d) Mount flow computer and connect cables to transducers

e) Start up flow computer, and then set initial adjustments

f) Check basic flow operation of installed meter.

g) Print out Site Setup and System Diagnostic parameters for future reference

7. Clamp-On Transit-Time Leak Detection System Description

Since substantial literature describing the clamp-on transit-time leak detection system in great detail is available, this paper will, in the interests of space, limit itself to a broad description of the system. Additional information can be obtained by writing or calling the author:

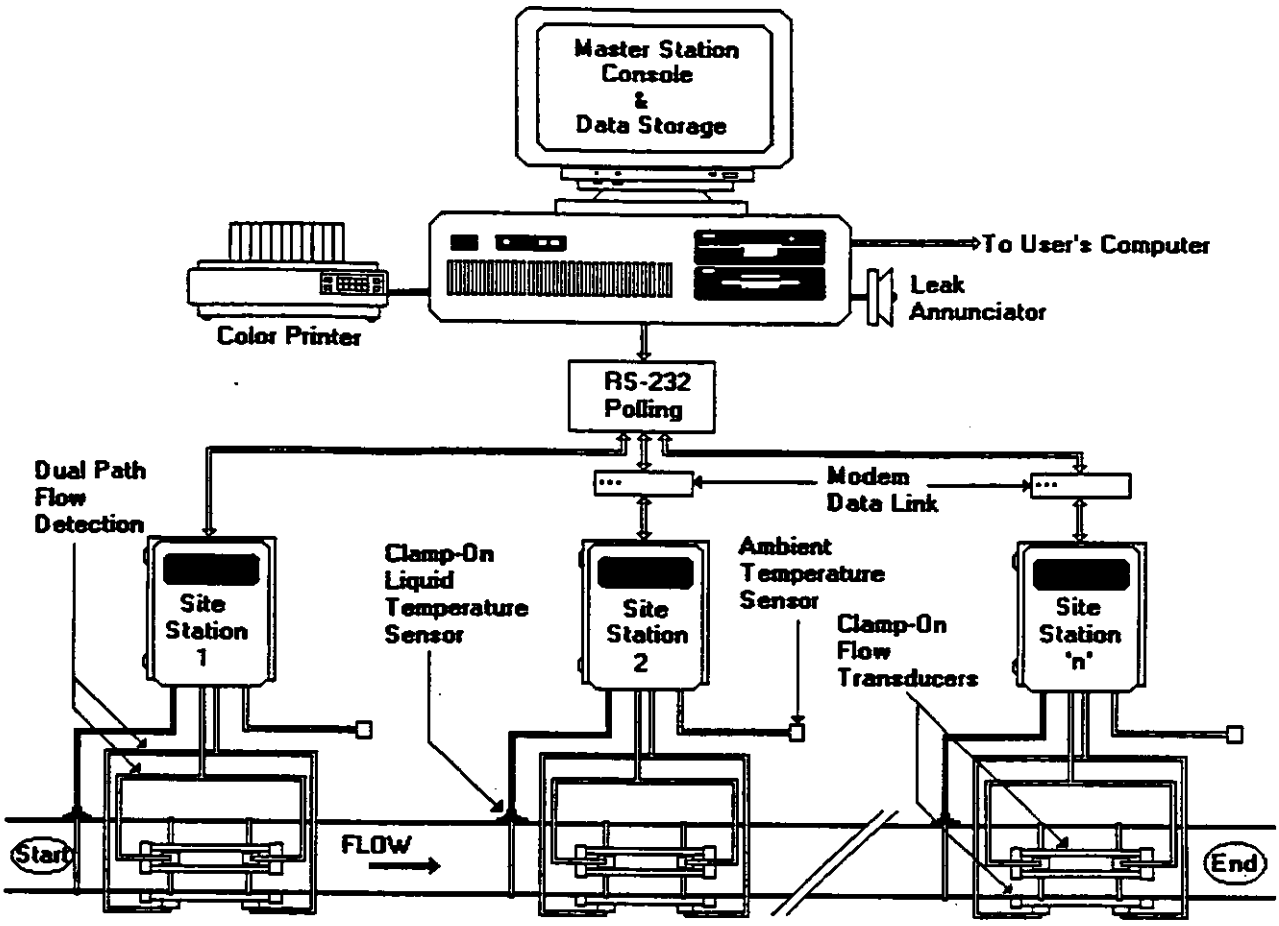

Figure 2: Transit-Time Leak Detection System Schematic

Referring to Figure 2, it is seen that the clamp-on transit-time leak detection system consists of a number of site stations, installed at various distances from each other along the pipeline. The separation between site stations is chosen dependent on the risk factor of the intervening segment. The maximum segment length recommended is about 30 miles, although test cases involving segments over 100 miles have been successful.

As shown, each site station includes a single, dual or triple path clamp-on transit-time flow computer, plus clamp-on temperature sensors to measure both the liquid and ambient temperature, as required by the type of system specified. Also included at each site station is communication equipment, for either phone line, radio or satellite communication, as required.

The master station is also equipped with a communication port. the master station is the control center of the system, and processes all incoming data to provide both alarms and pipeline operations data, dependent on which type of system has been specified. The master station also archives all incoming data into daily data files, which can subsequently be analyzed to permit system optimization, and to provide a playback capability in order to show due diligence, when necessary.

Master stations are available to handle any and all pipeline configurations, so that expensive and time consuming custom leak detection system design is avoided. Instead, provision is made for the actual physical configuration of any pipeline to be described in a generic topology file, which is prepared for installation into the master station. Thus the master station interprets all site station data by referring to the topology file, which tells the standard master station operating system how to handle this data to provide for accurate and reliable leak detection performance.

The master station polls all site stations once per minute simultaneously. Some models can handle as many as 64 site stations, which can be on any number of independent individual pipeline systems as desired, up to the capacity of the master station. Upon receipt of the data, it proceeds to compute the temperature and line pack corrected volume balance for each segment of each pipeline registered. It also computes a number of additional factors which are useful in determining the validity of a leak alarm, such as the current application and equipment operating conditions. It also computes data useful for management of the pipeline, such as interface detection, batch tracking, liquid type identification, liquid quality determination, pig detection and many other important factors.

At the completion of this computation, which takes less than one minute, The master station publishes all computed data. If there is a breach of one of four leak detection thresholds, for 1, 5, 15 and 60 minute periods, the leak alarm is activated, generating both audible and visible alarms. Up to this point, the system need not be actively monitored, unless its many operations management screens, such as those for interface detection or batch tracking, are utilized for pipeline management.

As detailed in the additional available literature, a complete description of the many data screens are provided. Suffice it to say, master stations can produce a substantial amount of very useful data, all of it presented in both graphics and numeric data screen formats. These are displayed by simply depressing an appropriate master station 'hot key'. The screens are organized in a sequence so that the system operator can quickly determine which segment of the pipeline generated the leak alarm. Many of these screens are of multi-graph type, which permits the inspection of as many as four different data items simultaneously. The operator, or user designated staff, can then easily associate various cause and effect relationships, so as to quickly make a decision as to the validity of the leak alarm.

In addition, communication links to the leak detection system supplier's headquarters perm experienced system engineers to assist in diagnosis of leak conditions.

In order to avoid false alarms, the system should include an automatic application condition monitoring function. If deteriorated liquid or other operating conditions are responsible for a leak alarm, there is an automatic readjustment of the alarm threshold to avoid the false alarm. However, such a condition will also trigger the leak warning so as to alert the operating staff of the potential of an as yet undeclared leak alarm. In addition, the process of optimization further ensures against the generation of false alarms, while also enabling the setting of the minimum possible alarm threshold.

7.1 LINE PACK & THERMAL EXPANSION/CONTRACTION DETECTION

The clamp-on transit-time flowmeter automatically detects both line pack and, for systems in which temperature gradients are expected, it also determines the effect of liquid and pipeline expansion or contraction, so as to preclude either false alarms, or failure to detect a leak.

a) Line Pack Detection
The clamp-on transit-time leak detector has a unique advantage in the detection of line pack, or unpack. This is because compression of the liquid, as in line pack, also increases the liquid density. This increase in density is sensed as a sudden increase in Vs, the liquid's sonic propagation velocity. Thus, by correlating the increase in flow rate with the increase in Vs, it is easy to confirm that the current segment volume imbalance is due to line pack, and not a leak, thus preventing the declaration of a false leak alarm.

However, during the process of optimization, a determination is made as to the amount of liquid which is normally packed in each pipeline segment under.various flow conditions. Using this data, the leak detection system is able to sense if the actual liquid unbalance, during line pack events, is within the historical limit. If it exceeds this limit, as if the pipeline leaked during the line pack event, the system will immediately declare a leak alarm.

b) Correction for Thermal Expansion or Contraction
The clamp-on transit-time leak detector senses both the liquid and ambient temperature at each site station. It uses this data, in combination with the thermal model of the pipeline, contained in the master station topology file, to compute the temperature of the liquid and pipe wall at 100 points between site stations. This is done for all pipeline segments once per minute. These temperatures are used to compute the incremental expansion or contraction of both the liquid and the pipeline for each segment registered in the master station. This volumetric data is either added to, or subtracted from, the measured segment volume imbalance, so as to prevent either a false alarm, or masking a true alarm condition.

Assuring that the thermal model of the pipeline is working properly is relatively simple. One of the points whose temperature is computed is at the next site station, where actual measurement of the liquid temperature is being made. If the parameters of the thermal model were not correct, the computed and measured temperatures would not coincide. If they do not coincide at first, the process of optimization determines the correct thermal model operating parameters to achieve coincidence. Since both the computed and measured temperatures are presented on one screen, the operator can easily confirm that the thermal model is operating properly.

7.2 INTERFACE DETECTION
Interface detection is frequently performed by sampling the product in the pipeline periodically, and physically measuring its density. Alternatively, expensive and maintenance prone densitometers are used. But, note that Vs, the sonic propagation velocity of the liquid, is a function of liquid density. The clamp-on transit-time flowmeter can sense the change in Vs, and thereby density, with considerably more sensitivity than conventional densitometers.

The clamp-on transit-time leak detection system uses this Vs data, in combination with the measured liquid temperature, to compute the 'sonic signature' of each liquid. This uniquely identifies the liquid, enabling computation of its current density, and its density at 60°F.

This leads directly to the API number determination. Both the sonic signature and API number of the batch are plotted as a function of time. These screens are available for real time interface detection, and the data is also made available as a local output from each site station.

7.3 BATCH TRACKING
Since the clamp-on transit-time leak detection system can identify the liquid in the pipe at all times, and has full knowledge of the time history of flow rates, it is a relatively straightforward matter to compute the location of all batch interfaces within each pipeline segment. Marking the interfaces between batches also permits the system to compute the actual standard volume of each batch. Thus data screens are available to show the actual volume of each batch, where the interfaces are at any given time, and to predict the arrival time of all batches at their next target site station.

7.4 CUSTODY TRANSFER

Clearly, the entire batch tracking function available from clamp-on transit-time leak detection systems is based on the ability of this ultrasonic flowmeter to identify each batch of liquid, its density and API number. It is already well established that clamp-on transit-time meters can be volumetrically proved, using the conventional API proving method. The only question which remains to determine its candidacy for custody transfer service is to establish its long and short term calibration stability. Tests of this type have shown excellent conformance to batches measured by conventional turbine and PD meters, with repeatability to better than 0.04% in actual field trials.

Referring back to the previously described parameters, the clamp-on transit-time flowmeter performance could be superior to conventional intrusive meters. For example, it has greater flow rangeability, being both completely linear and bi-directional, from minus to plus 60 feet per second. It has greater sensitivity, 0.001 foot per second, at all flow rates, even at zero flow, at which conventional meters do not operate. It has no change of calibration due to friction, wear or aging, since it is entirely non-intrusive, and uses only drift free digital computation.

This system senses the type of liquid in the pipe continuously, and therefore can instantly and continuously adjust its calibration to previously optimized parameters. Conventional meters are limited to infrequent periodic proving, which cannot maintain calibration as the product parameters may vary from those present during the proving cycle.

While volumetric accuracy is important, so is the assurance that the product whose custody is being transferred is of the grade specified, and is free from contamination by water, free gas, or by non-specified product. The transit time meter's sonic signature confirms product type and grade continuously, and the site station diagnostics instantly identify the presence of both water and free gas.

Substantial data has been obtained to confirm that the clamp-on transit-time meter has the potential to provide custody transfer capability. It is expected that as more industry experience is gained with this type of system, a formal evaluation of this potential will develop, with acceptance as a standard after sufficient data has been obtained. However, users of the transit-time leak detector system will have an opportunity to compare its performance against their conventional meters, since these systems can be operated in parallel with existing meters.

7.5 LEAK LOCATION

Finding that a leak condition exists, and terminating flow so that injury to people and the environment is prevented or minimized, is the primary requirement that society places on our industry. But, in the real world, locating the source of the leak quickly, so that remedial action can be taken immediately, is what is necessary to be able to continue operations at the earliest possible time. Since the terrain through which pipelines pass is frequently populated, it is essential that the actual location of the leak be identified as precisely as possible. Uncertain 'poking around', with the resultant loss of public confidence, is becoming intolerable.

One of the most important benefits of the transit-time flowmeter is its ability to keep track of the different types of liquids in the pipeline at the time that a leak is discovered. This permits an exact 'triangulation' to be made of the pressure waves that emanate from the source of the leak to each segment's adjacent site stations. As a result of this capability, transit-time based leak detection systems show the promise of being able to place the source of even very small leaks to within meters of their actual location. In addition, advanced leak detection systems of this type have the ability to detect and warn of the development of even pin-hole sized leaks.

7.6 PIG DETECTION

Unlike conventional intrusive meter based systems, the clamp-on transit-time leak detector is a full bore system. Accordingly, no expensive bypass piping is needed to shunt pigs around the site stations.

In addition, the pig will interrupt the sonic beam as it passes through the site station. The site station is programmed to interpret the interruption duration, from the then current signal conditions, as detection of a pig. At the next polling, this pig detection alarm is transmitted to the master station, where the time of passage is displayed. This pig detection alarm is also available for local display at each site station.

The clamp-on transit-time leak detection system can be procured for leak detection service only, or can be upgraded to also serve as a pipeline management system when purchased, or at any time thereafter.

8. Field Performance of Installed Transit-Time Leak Detection Systems

Clamp-on transit-time leak detection systems have been in operation in the field for several years. Over this period, substantial data has been obtained in a variety of crude and product applications which substantiate the performance predicted by the specification parameters of the system. The data presented below is actual field data, obtained from the archived data files automatically saved by each system. The types of service from which these files were obtained include:

a) *A 22 inch interstate crude pipeline, handling as many as 15 different types of crude. Segment lengths are from 30 to over 100 miles*

b) *A bi-directional 12 inch pipeline, between a refinery and a tank farm, handling extremely viscous liquids.*

c) *An 8 inch pipeline handling aviation fuel in Arctic environment, covering a length of over 70 miles.*

d) *A 36 inch pipeline, handling many grades of crude, and crossing an Alpine mountain range.*

Among the examples shown below are:

Figure 3:	**A leak test performed under blocked Line conditions**
Figure 4:	**A leak test performed under high rate flow conditions**
Figure 5:	**Interface detection on a multi-product pipeline**
Figure 6:	**Batch tracking on a multi-product pipeline**
Figure 7:	**Liquid quality monitoring in refinery delivery application**
Figure 8:	**Liquid data screen identifying liquid data and condition**
Figure 9:	**Diagnostic screen showing site station operating conditions**

8.1 BLOCKED LINE LEAK DETECTION

Direct detection of leaks in a blocked line by the volume balance method requires that the flow meter operate with high sensitivity under zero flow conditions. This attribute of the clamp-on transit-time flowmeter is illustrated by Figure 3.

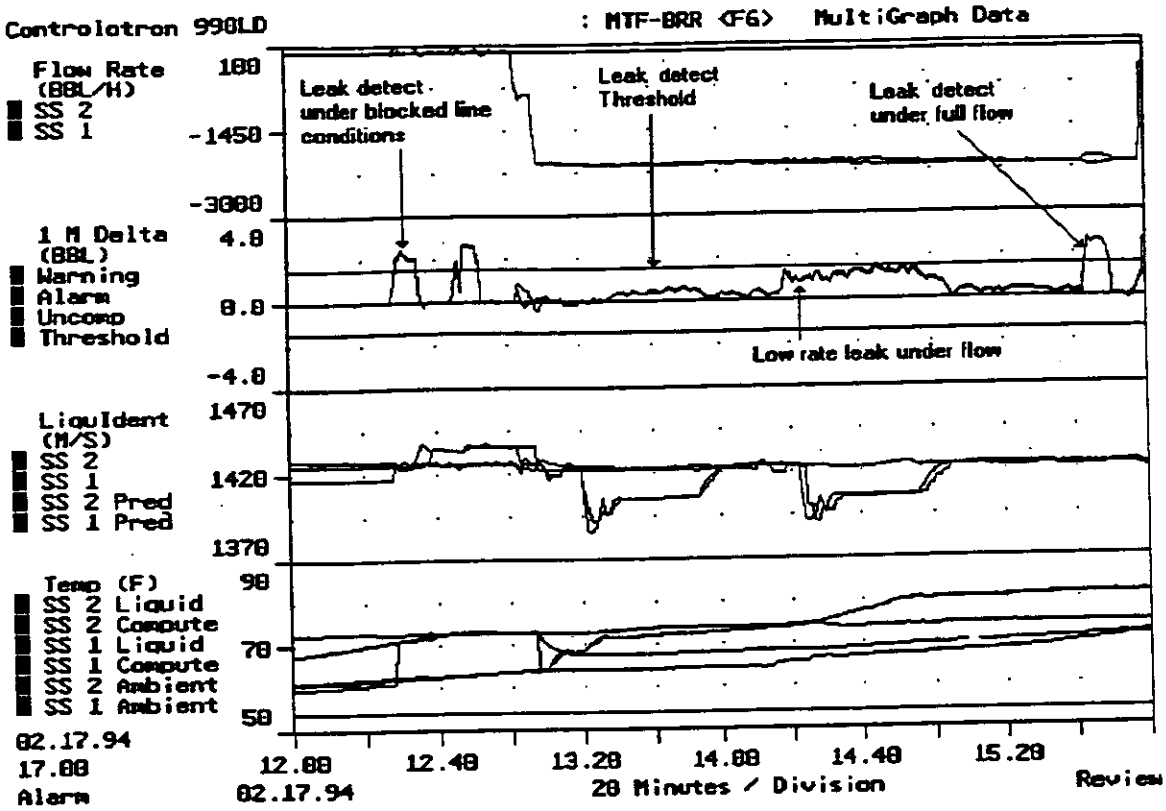

Figure 3: Leak test under blocked line condition

As shown, this is a multi-graph screen produced by the master station for a 12-inch line flowing highly viscous product. The upper trace shows the flow rates for each of the two site stations bounding the segment. As can be seen, the flow is effectively zero from 12:20 on February 17, to a little after 13:00 hours. A leak of around 2 BPM, lasting around 7 to 10 minutes, was provoked on two occasions; at 12:27 and again at 12:43. This leak was driven by line head pressure only. As shown on the second trace, which shows the segment volume imbalance for a 1 minute integration period (1 minute delta), both leak events passed through the leak alarm threshold, set to 1.5 barrels, and triggered the alarm within 1 minute. Also shown on this multi-graph screen are the Liquident sonic signature values, and the computed and measured temperatures of the liquid, and the ambient temperature, at each site station.

8.2 LEAK DETECTION AT HIGH FLOW RATE CONDITIONS

A high flow rate leak was created on the same pipeline as described previously, as shown on Figure 3. The flow rate was set to approximately -2000 barrels-per-hour (this is a bidirectional line). At 15:42 a 2 BPM leak was created, the same rate as instituted earlier when the line was blocked. As may be seen on the second trace, the 1 Minute Delta, the alarm threshold was crossed in 1 minute. In all respects, detection of the leak at high flow rate was identical to its detection under blocked line conditions.

Note that at 14:20 a leak smaller than the 1 minute alarm threshold was created. As shown on Figure 4, the MultiGraph Delta screen, the second trace, for the 5 minute integration period, detected the leak within two minutes.

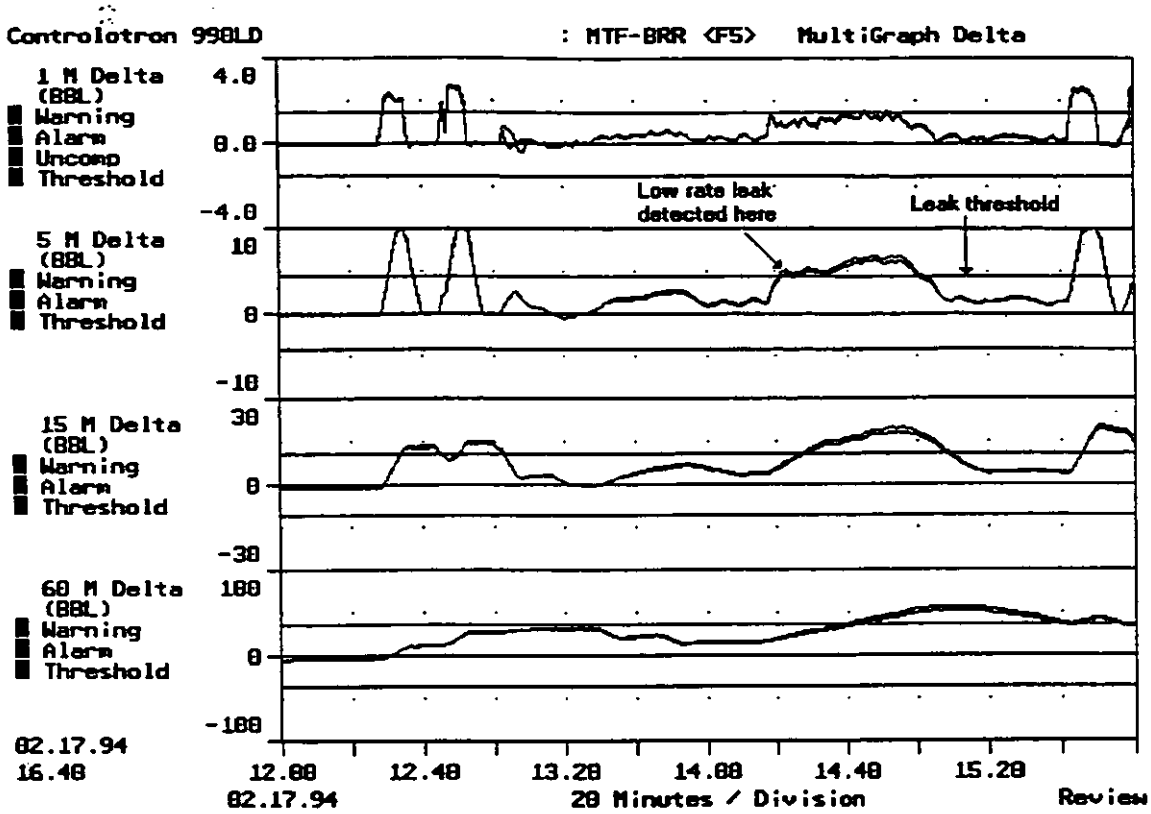

Figure 4: Leak test under high rate flow condition

8.3 INTERFACE DETECTION & BATCH SIGNATURE ON A CRUDE PIPELINE

The sonic signature graph shown as Figure 5 was obtained by monitoring flow on a 22-inch pipeline, for a segment of over 100 miles. Liquident is the 'sonic signature' of the different batches of crude which flow, and is directly related to liquid density.

As may be seen, each batch flowing down the pipeline generates a characteristic sonic signature shape, dependent on the variation of product within the Batch. As may be seen, these shapes are essentially identical as each batch passes first one site station, and then the next site station down the line. Also clearly visible are the interfaces between the batches.

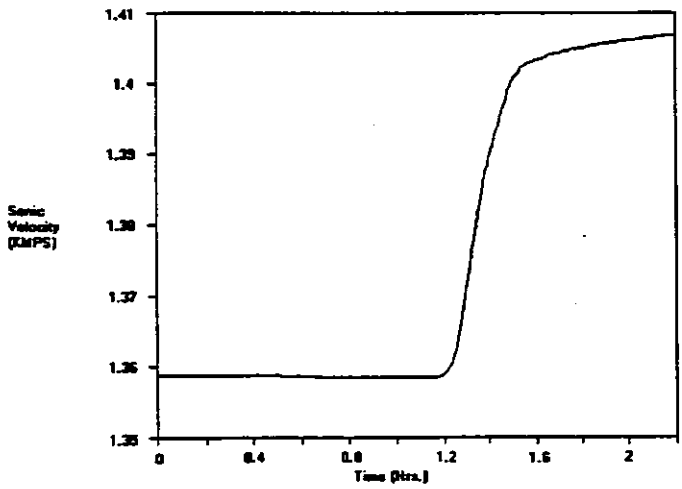

Figure 5: Interface detection on multi-product pipeline

The distinctive and easily recognizable batch signature shapes on the screen enable pipeline operators to cut each batch as it arrives at the terminal. As shown below, the system also provides a batch tracking screen which predicts the arrival time of each batch at the next site station, and also identifies the materials API number, and its volume at the standard temperature of 60°F.

8.4 BATCH TRACKING

Consistent with the clamp-on transit-time system's ability to visualize the flow of batches down a pipeline, is its ability to quantify the batch volume, and its position in the pipeline numerically. Figure 6 shows a typical batch tracking screen produced by the master station. As shown, it provides a listing of all batches still in the pipeline, indicating the standard volume of each batch, its average API number and the estimated time of arrival of its leading Interface at the next site station. These values (times, BBLs, etc.) are automatically re-computed as rates change.

Controlotron 990LD <F4> Batch/Liquid Status

Pipeline: MVP **Date/Time: 03:28:94 19.55**

Batch/Tag		Date/Time		Avg API	BBL	Mins
0019	DOMSWT	3.28.94	17:37	30.2	20560	714
0018	CSTLMIX	3.28.94	12:12	25.2	38001	460
0017	NIGRIAN	3.28.94	07:34	20.3	39222	198
0016	CSTLMIX	3.28.94	05.42	25.2	17232	83
0015	DOMSWT	3.28.94	04:04	30.1	15662	3
0014	CSTLMIX	3.28.94	02:12	25.2	16304	1018
0013	NIGRIAN	3.27.94	23:55	20.3	21258	876
0012	CSTLMIX	3.27.94	22:42	25.2	10553	805
0011	DOMSWT	3.27.94	16:25	30.1	51941	458
0010	CSTLMIX	3.27.94	14:02	25.2	22220	310
0009	NIGRIAN	3.27.94	13:01	12.9	9164	248
0008	EXTSOUR	3.27.94	10:15	28.5	21233	0

Figure 6: Batch tracking on a multi-product pipeline

8.5 LIQUID QUALITY MONITOR

Custody transfer is based strictly on proved volume transfer. Liquid quality is usually checked by sampling, which is available as reported data only after a batch has been delivered. In terms of value, liquid quality is certainly as important as liquid quantity in determining the value of the product which is being transferred. In this regard, the real time liquid quality monitor provided by the master station can be an important revenue producer.

Figure 7 shows the flow of processed product from a refinery to a tank farm. Note the characteristic 'bump' which appears on the sonic signature trace coincident with the initiation of flow. A short time later this bump arrives at the tank farm. This bump is water, which collected at the bottom of the holding tank at the refinery during the time that the batch was being processed. Its identification as water enables this contamination to be cut out of the batch prior to its being sent to its holding tank at the tank farm.

8.6 LIQUID DATA SCREEN

Of great value in the operation of a pipeline is information which shows the actual liquid in the pipeline, as opposed to the presumed liquid based on the 'name' of the product. The liquid data Screen, shown if Figure 8, identifies the actual sonic signature value, the Reynolds number under current flow conditions, the liquid viscosity and the liquid API number. As may be seen on a typical crude oil plot, the sonic signature is quite variable, indicating non-homogeneity. It is relatively easy to see how proving conventional intrusive flowmeters only once per batch (if that often with crude oil) could lead to erroneous batch totals caused by the normally unrecognized variability of liquid properties.

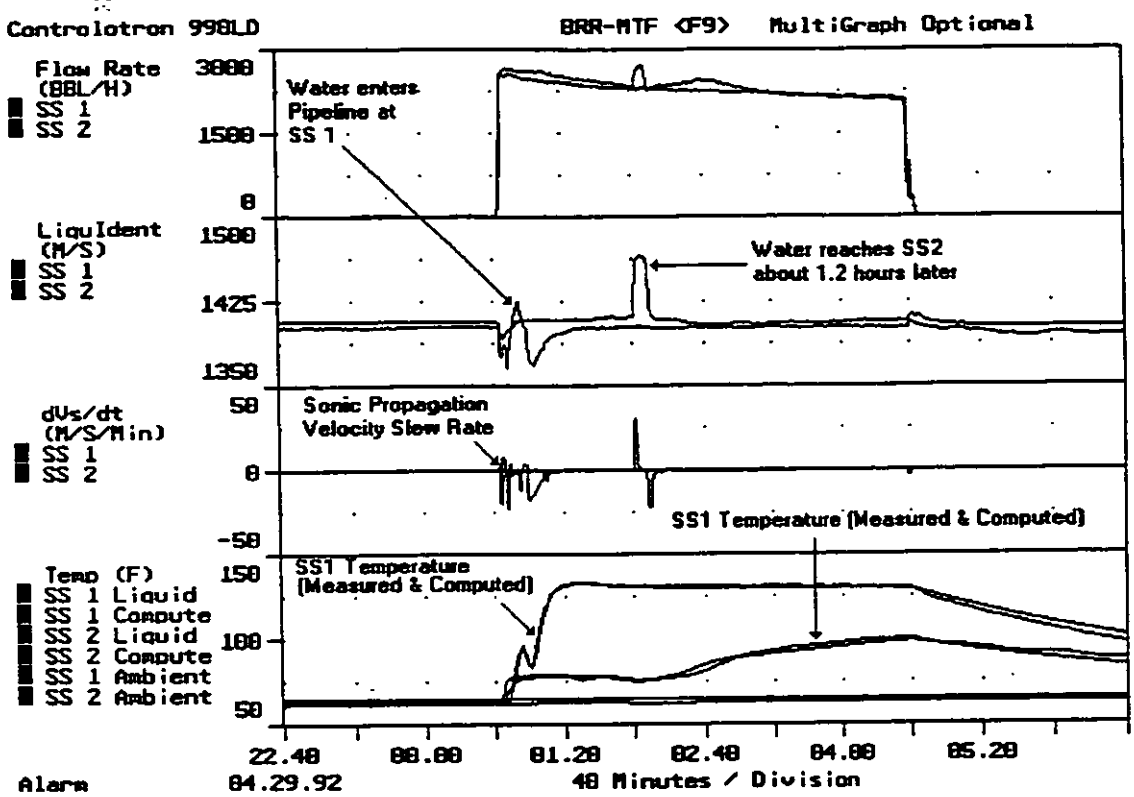

Figure 7: Liquid quality monitoring for refinery delivery

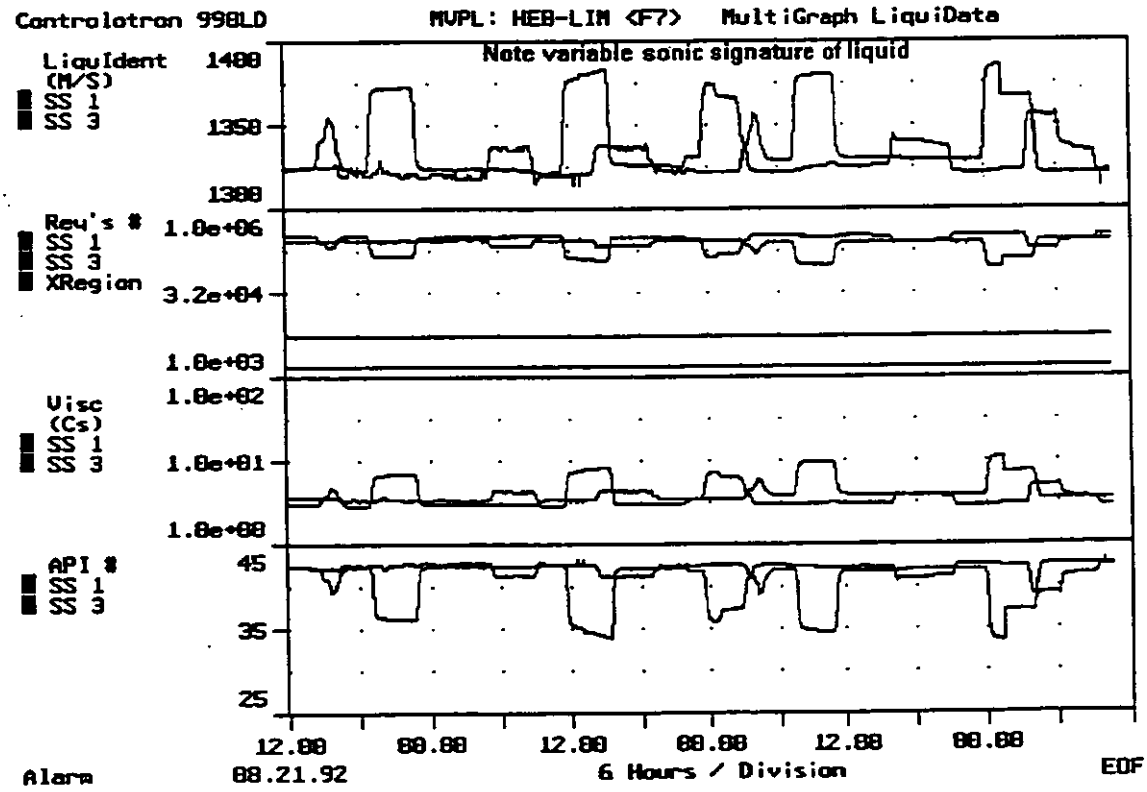

Figure 8: Liquid data 'sonic signature' screen

8.7 DIAGNOSTIC SCREEN

One substantial benefit provided by the clamp-on transit-time flowmeter is its ability to sense and report the condition of the meter itself, and of the liquid conditions at each site station. The diagnostic screen in Figure 9, updated once per minute, includes a variety of diagnostic data.

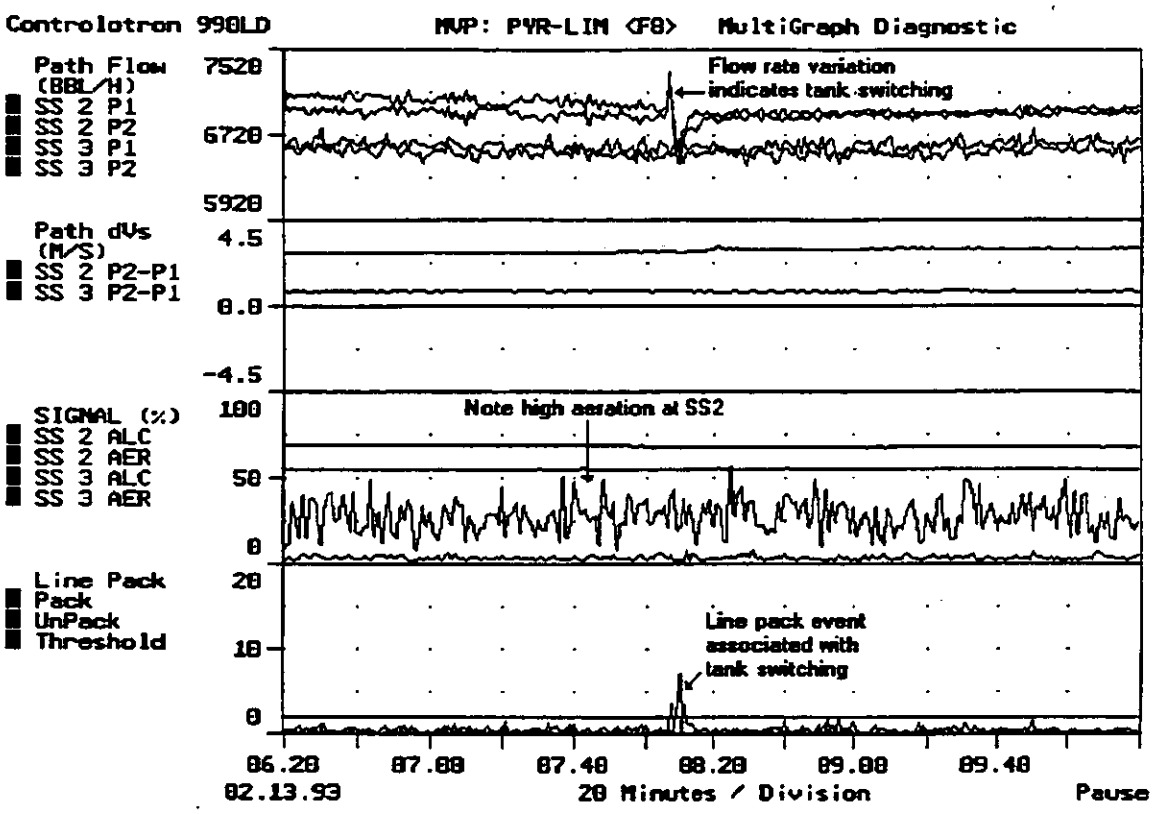

Figure 9: Diagnostics Screen

It shows the flow rate of each site station sensing path; in which a difference of rate is indicative of flow profile distortion. Any difference in displayed path sonic propagation velocity, Vs, is indicative of damage to a flow transducer.

The third trace shows the signal strength of the sonic beam, and as important, the amount of aeration being detected at each site station. This figure shows a substantial amount of aeration, which was later traced to a cavitation condition. This aeration would not have been identified by conventional intrusive flowmeters, and its net volume would have been counted as product, adversely affecting the transaction whose volume was being subject to custody transfer.

And finally, the line pack data shows exactly when a line pack or unpack event occurred, and its relative strength. In the event that any site station stopped operating, an immediate alarm is declared, and the offending site is identified on the master station screen which shows the pictorial of the pipeline installation.

9. SUMMARY & CONCLUSIONS

As shown, the clamp-on transit-time based leak detection system is a practical and field proven system for leak detection, and where applicable, for pipeline management. While not now approved for custody transfer, it has shown the performance capability to warrant its consideration for this important application.

It is significant that, due to its non-intrusive clamp-on technology, the effectivity of this system can be easily confirmed by site survey, even prior to purchase. At that time, sufficient data can be obtained to predict the leak detection performance that a fully installed system will provide on any pipeline. However, tests on all types of pipelines, flowing various grades of crudes and refined products, plus compressed and liquified gas, have been universally successful. It has proved compatible with a wide variety of pipeline environments, from tropical to arctic climates.

Unique among leak detection systems, those based on the clamp-on transit-time flowmeter provide a wide range of additional functions to pay back their cost. These added functions, such as interface detection, liquid quality monitoring, pig detection, etc., increase the efficiency of pipeline management and related activities, obviating the need for expensive alternative equipment, such as densitometers, viscometers, and maintenance prone intrusive flowmeters. Its performance has already proved successful on a variety of pipelines moving essentially every type of hydrocarbon liquid.

As such, the transit-time flowmeter based leak detection system is ready to provide the pipeline industry with a practical, affordable and quickly installed means of assuring the safety and integrity of pipeline operations.

Main Index

North Sea FLOW Measurement Workshop 1995

Paper 13:

STATUS OF THE FRAMO SUBSEA MULTIPHASE FLOW METER

4·1

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ABSTRACT

Multiphase Flow Meters have the last years become a fully accepted tool for well testing, well management and allocation metering. Significant experience has been gained in field installations and tests in topside applications. Another interesting area for use of multiphase flow meters is subsea installations where significant cost savings can be achieved if test lines and test separators can be avoided.

This paper summarizes the latest developments with the FRAMO Subsea Multiphase Flow Meter. It describes the measuring principle, the subsea packaging together with the intervention options which are based on diverless intervention. Procedures for remote calibration of the meter have also been developed and these are also explained herein.

Framo Engineering AS has been awarded commercial contracts for Subsea Flow Meters which will undergo full verification programs this Winter. The program includes both hydraulic verification in a multiphase flow loop and subsea intervention verifications at FRAMO's test facilities outside Bergen.

1.0 Introduction

The FRAMO Multiphase Flow Meter has already for several years been marketed and sold to various commercial offshore topside applications. The meter has been received by the market as a robust, simple and versatile principle, features which are of great importance to the environments where it is to be used.

Through several test installations, the FRAMO meter has proven its capability to consistently measure multiphase flow fully independent of upstream flow regimes, Gas Volume Fractions and Water Liquid Ratios. The Framo multiphase flow meter is also characterized by the extended use of standard off the shelf instrumentation, standard commercial programming tools and standard computers.

Through the commercial applications, in-house and third party testing the accuracy have been consistently improved primarily through improved gamma technology and the application of it. The FRAMO meter is today installed in several commercial installations where the meter will be used for allocation metering in addition to well testing (Martin, Woiceshyn, Torkildsen, 1992 /2/ and Olsen, Hansen 1994 /6/).

2.0 Functional Description

The FRAMO Multiphase Flow Meter (MPFM) is designed for measuring the individual flow rates of oil, water and gas as well as the pressure and temperature of a well stream.

An integrated Flow Mixer enables accurate and repeatable measurements independent of the upstream flow regime. It provides homogeneous flow conditions to the downstream metering section such that a Dual Energy Gamma Fraction Meter and a Venturi Momentum Meter can be applied.

The Dual Energy Gamma Fraction Meter features the ability to measure all combinations of oil, water and gas fractions, including 0 - 100% water in liquid ratio independent of the fluid being oil continuous or water continuous (Rafa, Tomoda, Ridley 1989 /1/).

The Gamma Detector System, Differential Pressure transmitter, Pressure transmitter and Temperature transmitters, which are all located in the measuring section of the MPFM, are wired to a Data Acquisition Unit which transmits raw data to a PC based computer which performs all calculations.

2.1 Flow Mixer

The purpose of the in-line mixer is to provide stable homogeneous multiphase flow conditions into the measuring section, independent on upstream conditions.

The Framo Flow Mixer (patented) is a static device and comprises a cylindrical compartment with a gas/liquid diverter, an injection pipe and a gas/liquid ejector.

When arriving the flow mixer, the most dense part of the fluid (i.e. the liquid phase) is continuously drained to the bottom of the compartment and through the ejector. The gas phase is diverted to the top section of the compartment and via the injection pipe to the ejector. In the ejector nozzle, a turbulent shear layer is generated. The operating principle may be compared to the operation of a carburettor. Minimum associated pressure loss is achieved by utilising this turbulent shear layer mixing process.

In order to simplify the measuring requirement, the primary objectives are to achieve a homogeneous flow in the venturi cross section, and to eliminate phase slip through the measuring section. Secondly, the volume of the mixer is large enough to accommodate for sufficient fluid hold-up in order to smoothen out the transients in multiphase composition during intermittent and slug flow conditions. Thus axial mixing of the multiphase flow is achieved.

2.2 Venturi Momentum Meter

The fluid velocity is measured with a Venturi Meter arrangement in combination with the Gamma Fraction Meter. This is possible since the Venturi Meter is located immediately downstream of the Flow Mixer. Here, the multiphase mixture can be treated as a single-phase fluid with equivalent mixture properties, and a standard single-phase venturi relations can be applied.

The venturi differential pressure is measured by a differential pressure transmitter. The differential pressure transmitter and pressure transmitter are equipped with remote seal sensors of pancake type, bolted to the sides of the Venturi section.

2.3 Dual Energy Gamma Fraction Meter

The Dual Energy Gamma Fraction Meter provides the fractions of oil, water and gas in the flow, which represents volume fractions since the gamma meter is located immediately downstream of the flow mixer.

Calculations of oil, water and gas fractions are based on the attenuation of two different gamma energy levels of a Barium 133 isotope.

The Gamma Detector System comprises the following main elements :

- A NaI(Tl) scintillation detector of rugged design complete with photo multiplier tube which detects the gamma radiation not absorbed by the multiphase fluid.
- Cable Penetrators complete with special cables.
- A High Tension generator for operation of the photo multiplier tube.

Figure 3 shows a cross section of the FRAMO Subsea MPFM. The meter when being installed is shown at left and during installation or retrieval at the right.

In the following, the main components of the FRAMO subsea multiphase meter are described:

3.1 Receiver Barrel

The subsea MPFM design utilizes a barrel styled subsea configuration with an insert cartridge which carries all active MPFM elements. The cartridge is locked into a receiver barrel.

The receiver barrel is permanently installed on the subsea structure and includes no active elements. There are no requirements for straight pipe lengths upstream or downstream the FRAMO Multiphase Flow Meter.

The receiver barrel serves the function as inlet and outlet housing and as a guide and support during installation of the MPFM insert cartridge. In addition, it forms the outer housing of the flow mixer. Standard (surface mounted bolted) flange connections at the receiver barrel will be used for connection of the flow meter inlet and outlet to the subsea tree or manifold piping. It is designed to take the actual design pressure.

The technology forming the basis of the subsea flow meter design is to a large extent developed for other FRAMO products. All vital elements are maintained in a vertical stack-up configuration forming a retrievable cartridge. The cartridge is, when installed, located inside a receiver barrel with appropriate lock-down and sealing functions.

The flow meter barrel includes the lower tapered lip profile connection hub for pulling the insert Cartridge together with the barrel thus making a rigid connection , i.e. radial clamp movement is converted to axial hub face loading. To seal the two hub halves, a lined seal groove is provided in each hub half to accept a metal seal ring.

3.2 Insert Cartridge

The insert cartridge incorporates the following main elements :

- Cartridge body with metal-to-metal seals and mechanical clamp connector
- Flow Mixer internals
- Venturi Section
- Gamma Isotope / Detector, Pressure and Temperature Sensors
- Flow Meter Data Acquisition Unit
- Connectors for power / signal and flushing media

3.3 Data Acquisition Unit

All instruments at the MPFM are wired to the MPFM Data Acquisition Unit at the upper section of the MPFM insert cartridge for signal conditioning and transfer of raw data to the MPFM Flow Computer located topside.

The MPFM Data Acquisition Unit comprises the following main elements:

- Power Input Switching Unit
- Power Supply and Solenoid Driver Module, 24 VDC
- CPU Module for signal conditioning and data communication as Modbus Slave
- MCA Module (Multi Channel Analyzer)
- Pre-amplifier Module for signal conditioning prior to spectroscopy analyzing

4.0 Insert Cartridge Retrieval and Re-installation

Normally, in new developments, the flow meter cartridge will be pre-installed inside the barrel and deployed as an assembly on the manifold structure. The Flow meter insert cartridge can then be retrieved and re-installed either guidewireless or guidewire supported. In both cases, a purpose built Running Tool will be utilized. If guidewires are used, guide posts will be run and guidewires established prior to deploying the Running Tool. Otherwise, the insert cartridge can be retrieved and installed simply by hanging the running tool in a wire, and use a ROV to guide the tool into position prior to retrieval or guide the insert cartridge into the barrel during installation.

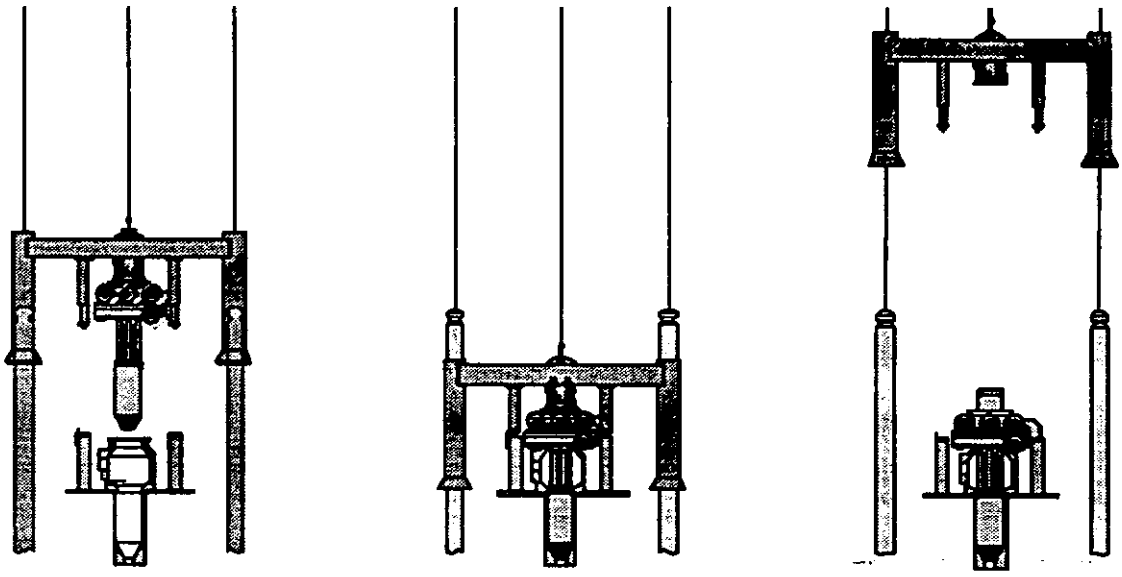

Figure 4. Installation procedure - guidewire assisted.

The following outline procedure applies for re-installation of the insert cartridge after maintenance retrieval. The intervention is in this example based on use of guidewires:

- The Insert Cartridge is picked up from a transportation skid by the running tool and positioned in the moonpool.
- All seals are checked / replaced
- The flow meter bleed valve is opened and stab connectors are checked
- The flow meter is lowered to the subsea structure.
- Initial guidance is provided by guide posts at the subsea manifold structure
- The Insert Cartridge is lowered into the barrel and the impact load is reduced by the cushion cylinders during the last phase prior to the cartridge seal lands out on its mating face at the top of the barrel.
- The ROV will then operate the clamp for locking and securing of the Flowmeter Insert Cartridge.
- The primary seal is now tested via the Running Tool / Subsea Power Unit.
- Finally the flow meter bleed valve is closed and the Running Tool is released from the Insert Cartridge running neck and retrieved to surface.
- The flow meter manifold isolation valves are now opened and metering can start.

A complete calibration of the FRAMO Subsea Multiphase Flow meter is performed by separate calibration of the four individual sensors (gamma detector, differential pressure transmitter, pressure and temperature transmitters) based on simple static measurements being an important feature offered by the system.

5.1 Gamma detector

The Gamma Detector is completely calibrated by performing a single-point static measurement on any known fluid.

By simply isolating the subsea multiphase flow meter and letting the fluids being trapped inside the meter settle, static conditions are obtained, and the single-point calibration measurement can be performed. Even without being correctly calibrated the meter will be able to identify whether the fluid is oil, water or gas. This method has been verified from the topside installed flow meters.

5.2 Differential pressure transmitter

The differential pressure transmitter is calibrated by performing a single-point static measurement following the same procedure as for the gamma detector. Since a closed wet-leg arrangement with remote seals sensors is used, the differential pressure at static conditions should equal the hydrostatic height between the two sensor elements.

The pressure ports in the venturi section are arranged with a facility that allows flushing. The feature is built in to reduce the risk for clogging of pressure ports, and procedures for such flushing will be implemented in purchaser's operational routines. Flushing media will be high pressure fluid supplied through a dedicated hydraulic line which can also be used to fill the measuring section with the same fluid for calibration purpose. The high pressure flushing media can either be hydraulic control fluid, chemical injection fluid, methanol or similar.

5.3 Pressure and temperature transmitters

For typical subsea applications, the operating conditions are such that small deviations in temperature and pressure reading have little impact. A comparison of the pressure and temperature readings with the readings taken at a X-mas tree or a subsea manifold will in most cases be accurate enough.

The pressure transmitter can alternatively be calibrated by the pressure in the flushing fluid when the meter is isolated and pressurized through the flushing line.

5.4 Changes in fluid component properties

Changes in fluid component properties as a result of changing pressure and temperature are automatically accounted for in the flow meter software.

However at conditions when a significant amount of water is produced, large variations in the water salinity will influence the multiphase flow meter readings.

The FRAMO Multiphase Flow meter has been provided with facilities to take a liquid sample to a sampling bottle subsea if required. The liquid is taken out from the bottom of the flow mixer compartment, which always will be dominated by liquids. A sampling bottle can be coupled to an ROV panel mounted to the insert cartridge. The bottle is filled by opening an ROV operated valve. When the valve is closed, the bottle can be released and brought to the surface by an ROV, where the salinity of the water can be obtained with standard laboratory equipment.

An alternative, direct on-line method for determining the water salinity on-line has recently been developed. The method is based on an analysis of the entire gamma spectrum, and will reduce or

Main Index

North Sea FLOW Measurement Workshop 1995

Paper 15:

THE KOS MCF 351 MULTIPHASE METER FIELD EXPERIENCE AND TEST RESULTS

4·2

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THE KOS MCF 351 MULTIPHASE FLOW METER - FIELD EXPERIENCE AND TEST RESULTS.

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SUMMARY

The KOS MCF 351 multiphase flow meter has been tested at four different locations for applications onshore and offshore. The variety of flow conditions have covered the operational range of the KOS MCF 351 meter. The meter have also been tested with flowrates outside the operational range.
Good results for liquid and gas flow rates and watercuts have been obtained over a large range of liquid and gas flowrates. Testpoints outside the operational range have demonstrated the KOS MCF 351 meter's capability and potentials for extending it's operational range. Generaly good repeatability is demonstrated for comparable flowrates.

Reliable installation in explosive (Ex) zone on an unmanned offshore rig with the MCF charged by solar power has been demonstrated. In addition operation in extreame ambient conditions with high temperature, high humidity and tropic storms have been problem free.
All results from the different tests are shown and disused on general basis. Variations in test results for comparable flow rates and diverging test results are discussed in detail.
All tests have demonstrated the flexibility, easy installation and reliability of the KOS MCF 351 multiphase flow meter. The KOS MCF 351 meter is a commercial available product launched in the market on a broad basis for all types of applications.

INTRODUCTION

Kongsberg Offshore a.s (KOS) has in co-operation with Shell Research (KSEPL) and A/S Norske Shell developed the KOS MCF 351 Multiphase Flow meter, ref. /1/. The development of the MCF Multiphase Flow meter technology started in 1991 and the first commercial KOS MCF 350 meter for oil external (oil continuos) flow was available in 1993 after extensive laboratory and field testing, ref. /2/.

The KOS MCF 351 multiphase flow meter is now a commercial product. This meter is designed for the full range of watercuts from 0 to 100% in the slug flow regime.
Further development of the MCF technology is ongoing and the target performance for the next generation MCF meter is an operational envelope covering bubble, plug and annular flow upto a given maximum GVF limit in addition to slug flow. The stratified and wavy regime will be measured by use of a slug generator, ref. /3/.

All four tests reported in this paper were executed in 1995 on the KOS MCF 351 meter. Three of the tests were real life field applications. Whereas the last was in a controlled environment at a laboratory using fluids from a oil field close to the facility.
The KOS MCF 351 meter has in addition been tested by Statoil, Saga Petroleum a.s. and Norsk Hydro a.s. (SSH consortium) in Hydro's multiphase flow laboratory in Porsgrunn, Norway. No testpoints on the KOS MCF 351 meter are reported from the test due to process conditions outside the operational range of the KOS MCF 351 meter.

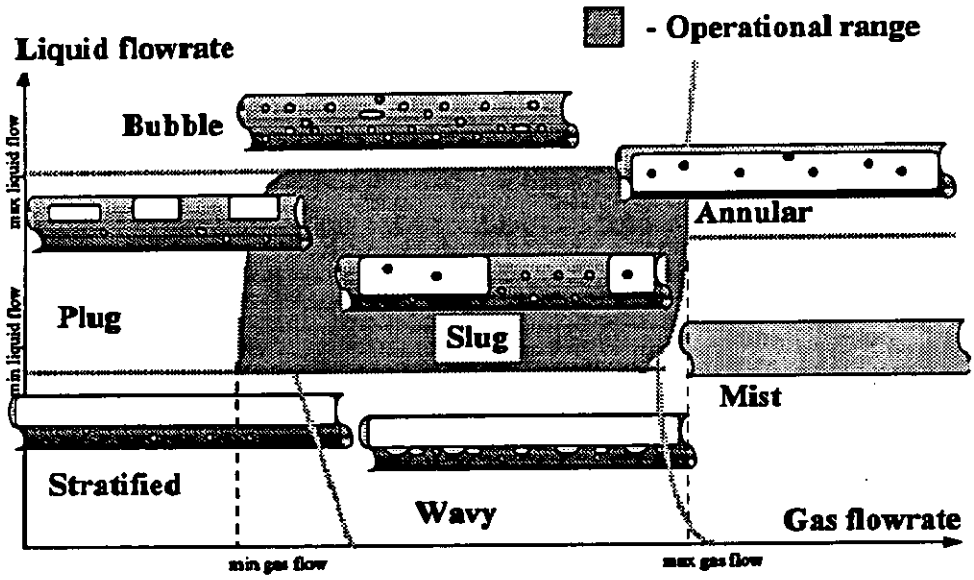

Figure 1 Operational range of the KOS MCF 351 multiphase flow meter

	3 inch meter		4 inch meter	
	Liquid m^3/h	Gas m^3/h	Liquid m^3/h	Gas m^3/h
Min flow	5	25	9	44
Full scale	50	215	88	380

Table 1 Minimum and Full scale flow specified for the KOS MCF 351 Mutliphase flow meter.

TEST LOCATIONS

The KOS MCF 351 Multiphase Flow Meter has been extensively tested at several locations under a variety of different process conditions, installation set-ups, onshore, offshore, at manifold, in flowline etc.
Specialities for the different installations will be described later.

Test site	Country	Company	Test period	Application
Rabi	Gabon	Shell Gabon	January-February	Onshore test
Tembungo B	Malaysia	Petronas Carigali	April-May & Aug.-Oct.	Offshore install.
Humble	USA	Texaco	April	Laboratory test
Luna Modular	Mexico	Pemex	July & August	Onshore test

Table 2 KOS MCF 351 Multiphase Flow meter installations 1995.

The installations at the different locations are according to requirements for the KOS MCF 351 meter; slugging flow and four meter upstream pipe with inner diameter corresponding to the size of the meter.

The different installations are motivated by a genuine need for multiphase flow measurements in the field. The installations include remote sites with solar powering where other alternative methods for well testing is either economically or technically unfavourable. The compact design, non-nuclear safe operation with low power consumption and flexible communication options makes the KOS MCF technology a favourable choice for these installations.
Although the world main market for multiphase metering is onshore, a number of offshore applications have an absolute need for this cost economical alternative for flow measurement. The technology base and the compact design of the KOS MCF 351 are favourable for the meter. Easy and safe installation combined with the flexibility offered on communication interface to the meter are big advantages for a multiphase meter for field use both onshore and offshore.

TEST SET-UP AND RESULTS

All different installations are presented separately. Individual experience from the different tests is presented. The results for all tests are listed in addition to Figure 3, 4, 5, 6 and 7, where the KOS MCF 351 liquid and gas flow measured are plotted against reference measurements.

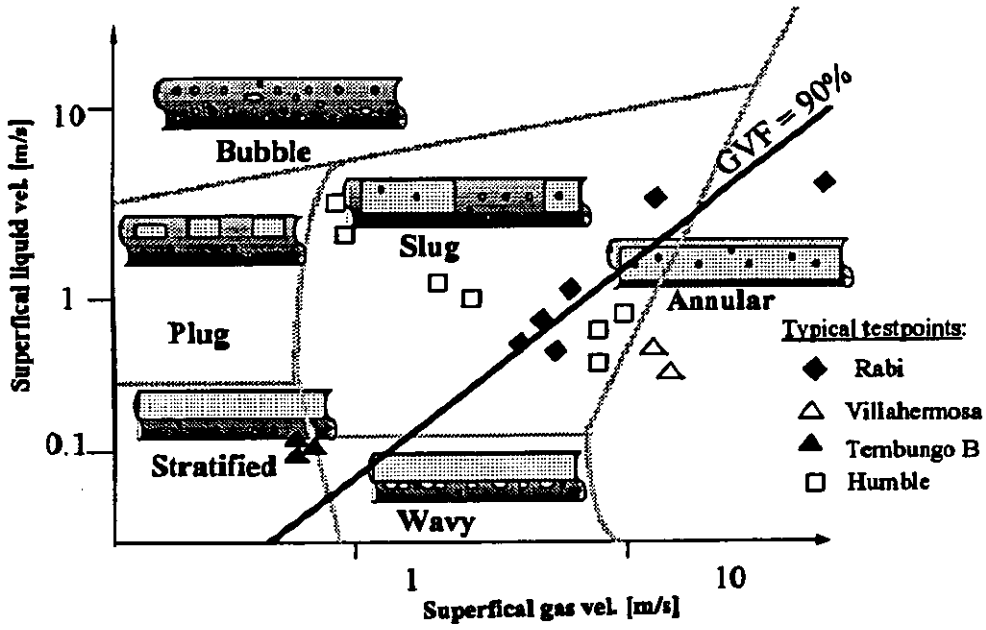

Figure 2 Typical flow conditions for different installations.

Average deviations and standard deviations for the different tests are calculated as percentage deviations related to full scale specified for the meter size (3 or 4 inch, see Table 1). This to better compare these numbers to the specified maximum and minimum deviation shown on Figure 3, 4, 5 and 6. Watercuts are given as absolute deviations both in the listing below and in Figure 7.
Note that all deviations and results presented include both errors in the KOS MCF 351 and in the reference measurements. For type of meter and excepted accuracy of the reference measurement see Table 7.

Rabi
This was the first field test of the KOS MCF 351 meter. A test at the same location of the KOS MCF 350 in 1993 is described in ref. /2/.
A 4 inch KOS MCF 351 meter was tested from week 3 to 7 1995 on 16 different wellflows with a total of 29 tests reported. This includes tests both in the loop on test manifold and in the flowline. One well was producing in water external emulsion (water continuos, ~76 % watercut). Test pressure was 5 bar(g).
In addition to the reference measurement (see Table 7) a liquid test tank was used to interpret the oil volume flowrate and percentage of water in the liquid.

The flowlines for the different wells tested are from 200 meters up to 2500 meters from wellhead to manifold. The terrain effect from the pipeline path had, for a majority of the well flows, an impact on the natural slugging flow. Longer more liquid filled slugs were formed.

For most well tests the multiphase flow was routed through an upstream test heater. Neither the heater nor the heat (increased liquid and gas temperature) had any effect on the flow and consequently no impact on the measurement. This leads to the conclusion that slugging flow is very robust to any upstream disturbances.
With the MCF meter installed in the flowline good results were obtained on gross liquid flow agreeing with tests in the manifold loop. (Note, only one well tested with KOS MCF 351 in productionline. One of the 29 test reported). The well tested with the MCF in the flowline produced with liquid slugs upto 200 meters length! The ten meters upstream 4 inch pipeline was therefore not enough to stabilise the slug velocity. An acceleration of the slugs were observed giving an underreading of gas velocity and concequently an underreading the gas volume flow of 10%.
The functionality of the electronics exposed to high ambient and fluid temperature in addition to repeating rainstorms was not effected.
Wax coating of the MCF was expected to be a problem. Even after flowing through different combinations of wellflows with high wax content for over 48 hours no wax coating was observed on the MCF sensorplates. For further discussion on wax coating see ref. /2/.

Results:
All results are show in Figure 3, 5 and 7, and they will be discussed later.
Average deviations between KOS MCF 351 and reference measurement are shown below. The spread in the results are given as standard deviations.

	Average deviation	STD
Liquid volume flow	-0,6 %	7 %
Gas volume flow	-0,7 %	10 %
Watercut	-1 %	12 %

Table 3 Test results at Rabi.

Luna Modular
One KOS MCF 351 is installed at the onshore Luna field (Luna Modular) in Tabasco, Mexico. The meter is installed in a flow loop giving access to 12 wells connected to a test manifold and separator, stock tank and orifice run. The flow line length are typical from 600 to 1400 meters, and diameters mainly 6 inch and 8 inch.

The flow regime occurring in this installation is annular due to high pressure (80 barg) giving higher actual gas density. The meter was reconfigured for annular flow by performing velocity measurements in the liquid film on the pipewall and in the gas core in the middle of the pipe.

Results:
Given the annular flow regime for which the meter originally was not designed for, it was still able to measure close to the rated accuracy for a number of the wells.

	Average deviation	STD
Liquid volume flow	-0,8 %	7,6 %
Gas volume flow	-3 % (*)	5 % (*)
Watercut	2,4%	7,8%

(*) Deviation for the one well test far outside the operational range is not used for this calculations.

Table 4 Test results at Luna Modular.

Tembungo B

The Tembungo B is an offshore production rig. Special requirement to the equipment was therefore evident. The KOS MCF 351 needed to be solar-powered. The solar-power cells with battery pack and all necessary equipment has been installed in Ex zone and was supplied by KOS.
The MCF has been installed in a purpose made pipesection on a manifold arrangement. All wells on the platform were connected to this manifold.
Reference measurements on liquid was done about 3500 meters downstream, on another offshore rig, Tembungo A (on the production from Tembungo B as a total). The test separator at Tembungo A was equipped as listed in Table 7.
All testing was done sequential by deferment. The reference testing on the well tested through the KOS MCF 351 meter was done directly after the KOS MCF test. This was done by closing in that specific well and measure the reduced total production. The accuracy on the gas outlet on the testseparator was not such that the relative small reduction in total gas flow could be detected with an acceptable accuracy. No gas reference measurements are therefore reported from the tests at Tembungo B.

The gross liquid production from the different wells are relatively low, from 14 m^3/d to 140 m^3/d. For the Tembungo B process conditions the wells with no exceptions were producing in stratified flow.
Motivated by this, a slug generator (ref. /3/) was installed directly upstream the KOS MCF 351 meter. This gave slug flow for all wells with exception of two extreme low producers. These wells are now closed in.
Four different wells were tested with liquid reference measurement only. A total of 32 well tests are reported.

Results:
All results are show in Figure 4, 6 and 7.
Average deviations between KOS MCF 351 and reference measurement are shown below. The spread in the results are given as standard deviations.

	Average deviation	STD
Liquid volume flow	-0,7 %	1,5%
Gas volume flow	- (*)	- (*)
Watercut	0 % (**)	0 % (**)

(*) No gas reference measurements reported.
(**) All wells had 0% watecut.

Table 5 Test results at Tembungo B.

In addition to the result shown in Table 5 comparison were done on total flow:

- Liquid flow average underreading of; 10.3%.
- Gas flow average overeading of; 10,7%

This total is based on flow from 11 wells. All these wells were tested through the KOS MCF 351 meter without single point reference (deferment testing on the separator).

Humble

The Joint Industry Program (JIP) "PERFORMANCE EVALUATION OF THE NEPTUNIA AND L4H PUMPS AND MULTIPHASE METERS" was formed to establish and report performance on a number of multiphase meters including the meter manufactured by Kongsberg Offshore a.s (KOS).
The KOS MCF 351 was tested at Texaco's Humble Flow Facility for a variety of crude oil, water and methane gas flow rates. A variety of different testpoints were tested based on the KOS MCF 351 specification. Tests were conducted with nominal total volumetric flow rates of 54-183 m^3/h (8150 - 27600 bbl/d), gas fractions of 50-95%, watercuts of 0-40%, all in slug flow.
Liquid flows above and below the specified range were also tested. These testpoint are formally outside the operational range, but are integrated in the results presented below and in Figure 4, 6 and 7.

Results:
The results show, ref./4/, that the KOS MCF 351 meter generally measured the total liquid rates within the specified +/-5% of liquid full scale. The gas rates were typically low at low gas volume fractions (i.e. 50%) and within specifications at higher gas volume fractions. The specified uncertainty in the gas flow rate is also +/-5% of gas full scale. The measured watercuts were typically within range or low, the specified accuracy is +/-3% absolute. Several tests were run outside the specified operating range, and the results of these tests were about as good as those from within the operating range.

	Average deviation	STD
Liquid volume flow	+5 %	9 %
Gas volume flow	-5 %	7 %
Watercut	-3 %	3 %

Table 6 Test results at Humble.

Discussion of test results

The test results for the four different tests are in general very good over a large range of flow conditions. These tests had flow conditions and watercuts covering the operational range of the KOS MCF meter, the slug flow regime. In addition lower flow rates in stratified flow regime and higher flow rates in annular flow regime have been successfully tested with good accuracy.
All test point are shown in Figure 3 to Figure 7. For all figures the measured flowrate or watercut on the KOS MCF 351 is compared to the reference measurement. The accuracy specification for the KOS MCF 351, which is +/- 5% of full scale (full scale 3 and 4 inch meter, see Table 1) for liquid and gas and +/- 3% absolute for watercut, is shown on these figures. The testresults are splitted between 3 inch and 4 inch figures to better compare the testresults with the specification for the KOS MCF 351 meter.

The liquid testresults on Figure 3 and Figure 4 are covering liquid flow rates with a turndown of about 1:15. A majority of the testpoints are well within the specified +/- 5% of liquid full scale. The very stable and regular slug flow conditions at the **Rabi** field gave liquid readings within the specification for 28 of the 29 test points reported. The one point of maximum flow was just above the specified maximum deviation reflecting a testpoint with high liquid flow and gas flow rate.

The production at **Luna Modular** gave, as described above, annular flow conditions. The flow rates as such are not extreme compared to the other wellflows tested. These different testresults are easily comparable in Figure 3 and Figure 5 for liquid and gas respectively. The pressure at **Luna** is however about 80 bar(g) giving an increased actual gas density which is narrowing the slug flow regime. In-house simulations and experience from the **Luna** field show that slug flow will not occur above a Gas Volume Fraction (GVF) of about 78%. One testpoint from **Luna** with reference liquid flow at about 18 m^3/h, see Figure 3, and corresponding reference gas flow at about 450 m^3/h, see Figure 5, is far below the specified accuracy. This specific testpoint is for a well producing far into the annular flow regime with GVF at 96%. For this flow condition the gas core of the flow is almost without liquid droplets. The crosscorrelation of gas velocities in the gas core is therefor suffering from lack of correlations in the gas flow. The dominant velocity profile in the liquid and gas could therefor not be established.

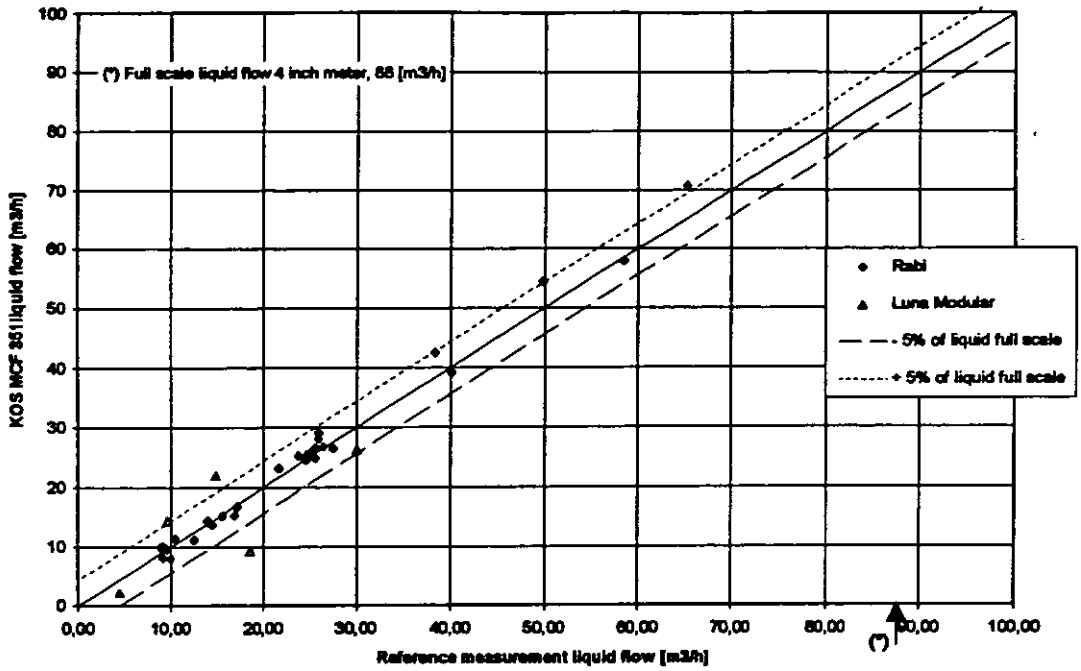

Figure 3 Test results liquid flow for 4 inch meters, Rabi and Luna Modular

For the **Tembungo B** test a slug generator was used to shift the stratified well flows into the slug flow regime. Low liquid producers down to 0,5 m^3/h , see Figure 4, was successfully tested with very good accuracy. These testpoints are comparable with corresponding testpoints for **Humble** and **Luna**. A difference is however seen in the results between **Tembungo B** and **Humble** test for low liquid production. In general the **Humble** testpoints shows an overeading for these low liquid productions. This is understood by two important factors:

1) Large gas entertainment in liquid phase
2) Testing of the KOS MCF 351 for low liquid range and below low liquid range.

Testing at **Humble** for low liquid flows are all combined with high GVF upto 95% giving large gas entertainment in the liquid phase. Measurement of this unexpected large gas entertainment was for the **Humble** test not sufficient and causing this overeading. A verification of this effect is also seen on measured watercut in Figure 8. Underreading for 10% watercut, as an example, is increasing with increasing gas entertainment, higher GVFs. As the watercut and gas entertainment measurement is interconnected in the KOS MCF 351 both the liquid flow overrreading and the watercut underreading is caused by the gas entertainment. The same effect is seen on the **Humble** data for 30% and 40% watercut.

Low liquid flows at **Humble** are below or close to minimum flow specified for the KOS MCF 351 meter. From in-house simulations and extensive field and laboratory experience such overreading is to some extent expected for the Humble flow condition and fluid properties. The **Rabi** and **Luna** testpoints for low liquid flows below 10 m^3/h demonstrate

the KOS MCF 351 meter capability to measure these low flowrates with acceptable accuracy. Remember that liquid flow of 10 m^3/h in a 4 inch meter is directly comparable to 5 m^3/h liquid flow in a 3 inch meter.

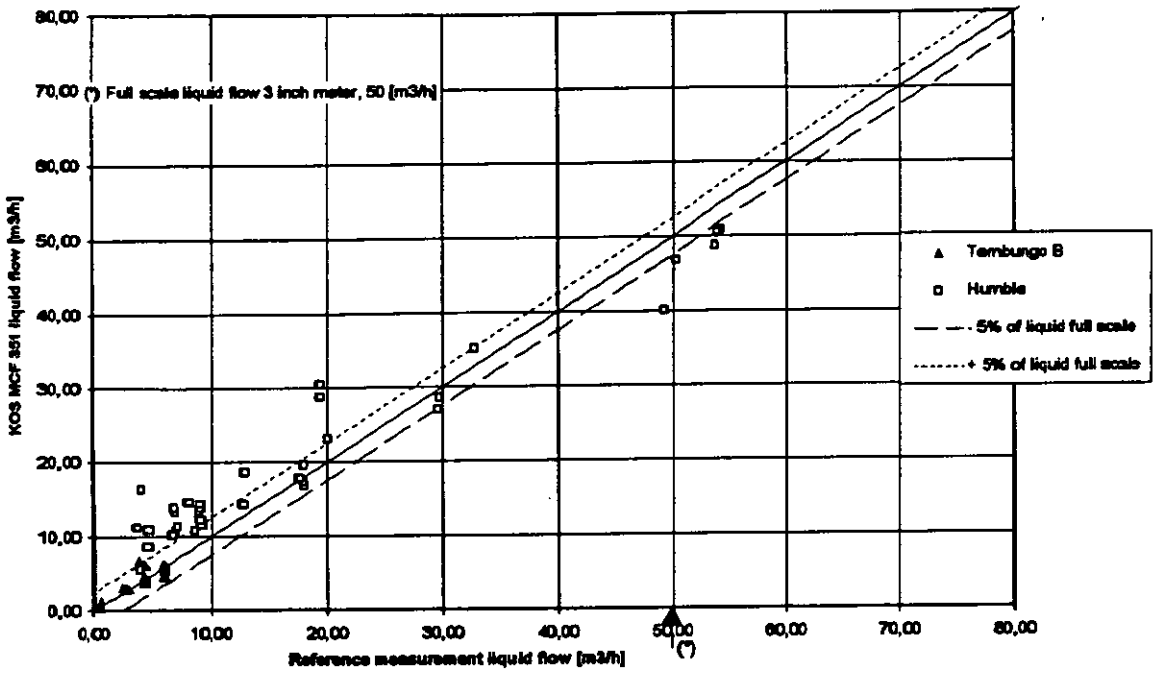

Figure 4 Test results liquid flow for 3 inch meters, Tembungo B and Humble

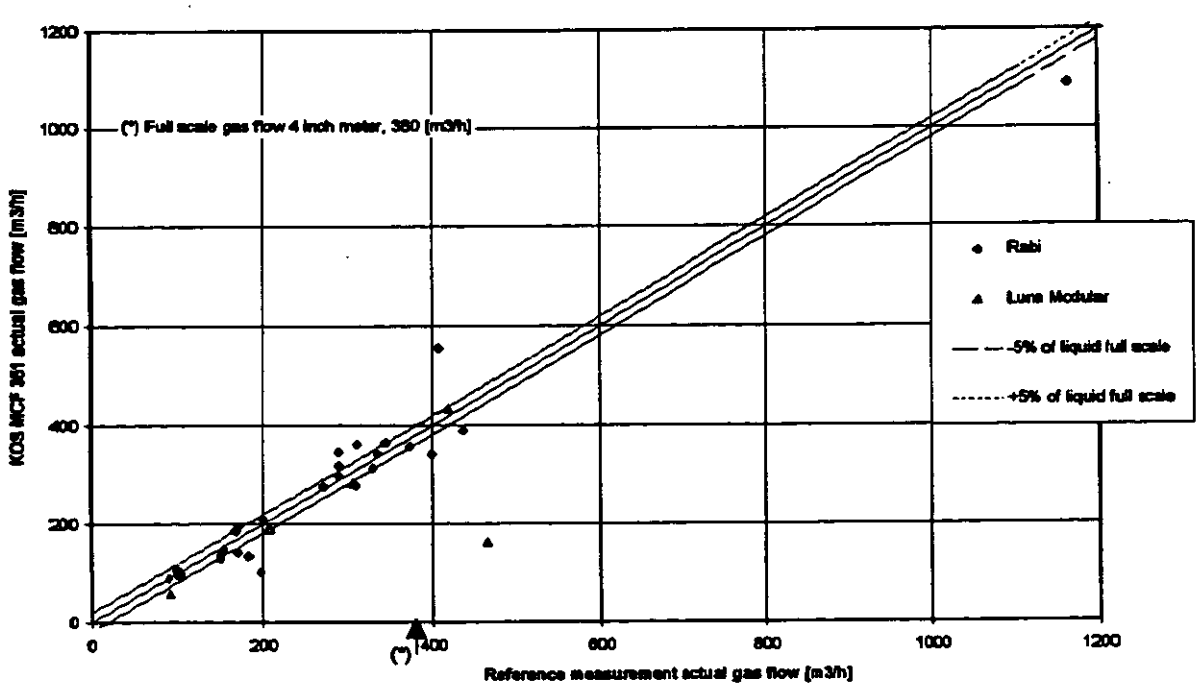

Figure 5 Test results gas flow for 4 inch meters, Rabi and Luna Modular

Underreading of liquid flow from **Humble**, see Figure 4, for higher liquid flows above maximum flow specified are for well flows with GVF at 50% and 70%. Measurement in this type of flow regimes, plug and bubble, is under development for use in later versions of the KOS MCF meter. For lower gas flow rates shown in Figure 6 an underreading is seen for the **Humble** data. The same tendency is seen for **Rabi** and **Luna** testpoints for lower gas flow rates. The larger deviations for the **Humble** data is due to the higher gas entrainment in the liquid phase and gas entrainment correction as discussed above.
The scatter on the **Rabi** gas flow accuracy shown in Figure 5 is mainly addressed to the combination of reference accuracy (see Table 7) suffering form surging well production giving large variations in testseparator pressure and consequently pressure drop over the orifice.
One extreme test point from Rabi is shown in Figure 5 on about 1100 m^3/h. Due to terrain effects the the well flow had a slugging behaviour giving valid measurement by the KOS MCF 351 meter.

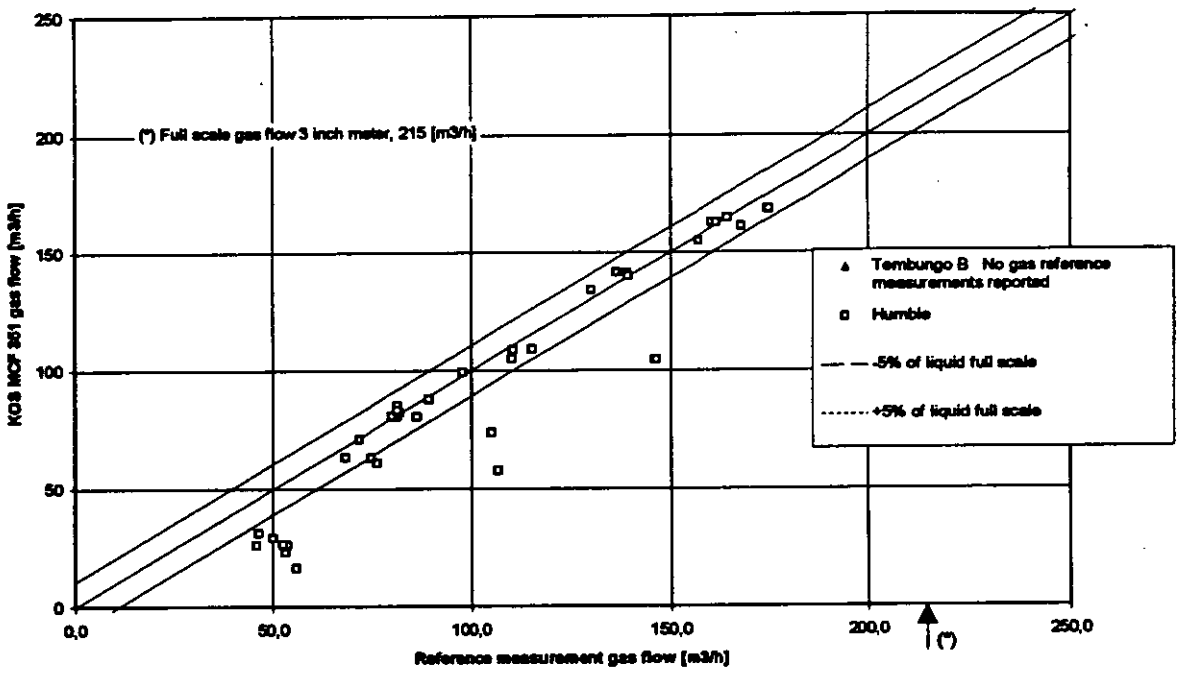

Figure 6 Test results gas flow for 3 inch meters, Tembungo B and Humble

Watercut in percentage is shown for all four tests in Figure 7. As discussed above the underreading of watercut for the **Humble** test is caused by large gas entertainment in the liquid phase. The **Rabi** watercut measurement is covering a large range from 0% to 76%. Maximum watercut at 76% is in water external emulsion (water continuos). The deviations is for 27 of the 29 testpoint within the specified accuracy.
The watercut at **Luna** is low and within specification with exception of one testpoint which on the KOS MCF gave 13,8% watercut and no water was detected in the reference stock tank. No repeated test was reported for this well and any errors in the KOS MCF 351 or uncertainty in the quality of the manual 'dip stick' stock tank testing has not been verified.

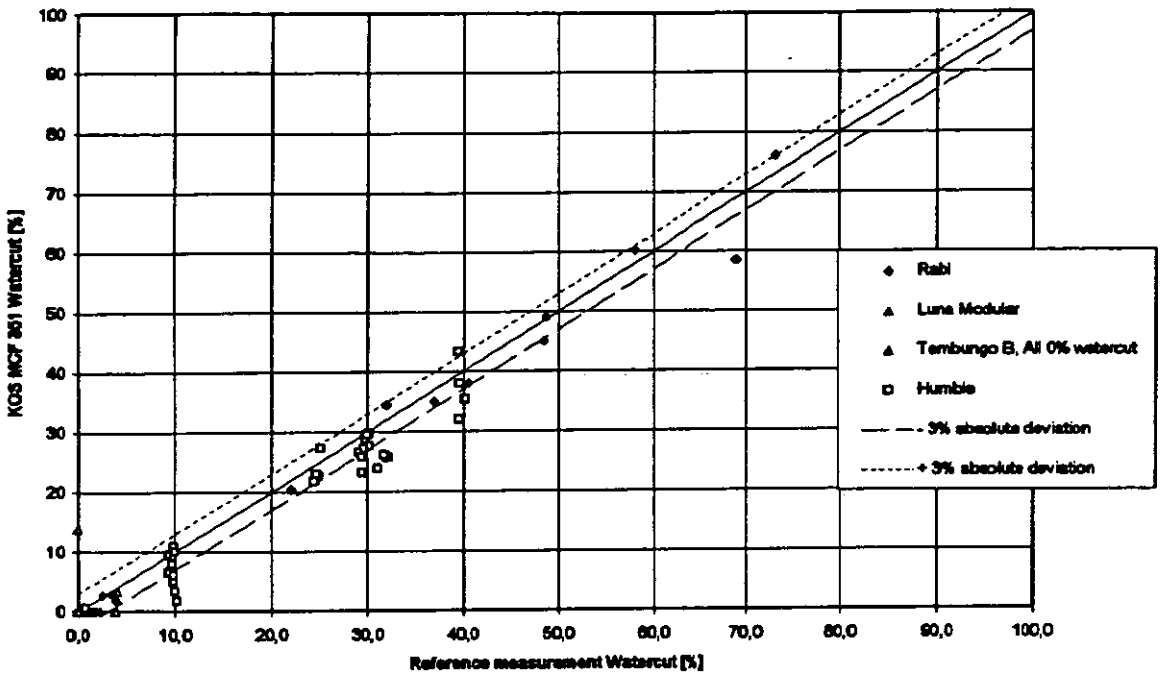

Figure 7 Test results for watercut, KOS MCF 351.

CONCLUSION

The KOS MCF 351 multiphase flow meter has through the reported field tests proven to be a reliable well test equipment. Good accuracy is shown over a large range of liquid and gas flowrates with a variety of watercuts. In addition excellent repeatability is demonstrated for repeated tests on one well and for different comparable wellsflows.

Further the KOS MCF 351 Multiphase flow meter has demonstrated it's potentials for reliable measurement outside the present specified operational range. Measurements on wells with low production in the stratified flow regime was successfully demonstrated at Tembungo B, Malaysia. The higher flow rates in annular flow regime, which is rather extreme for the KOS MCF 351, was demonstrated at the Luna field in Mexico.

The KOS MCF 351 meter is a field proven commercial product for the world market suitable for installation onshore or offshore. The KOS MCF 351 has flexibility for easy integration in any application.

Acknowledgement

This paper has been based on a number of people concentrating and focusing on the KOS MCF 351 meter performance in different corners off the world. This enthusiasm, the commitments established and hard work invested by the different operation organisation can not be appreciated enough.
In addition to the positive involvement from the management in Shell Gabon, Texaco Humble, Pemex and Petronas Carigali a special acknowledgement is hereby addressed to the different operational staffs. This acknowledgement is given for their positive co-operation and assistance during commissioning, start-up and testing.

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The North Sea Flow Measurement Workshop, October 1993

/3/ R.M. Pols and V.A. Olemans "Liquid slug generator for separated gas/liquid flow in pipes",
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/4/ Texaco EPTD "Performance Evaluation of Kongsberg Multiphase Meter",
JIP report July, 1995

Rabi	Meter type	Expected accuracy
Liquid leg	EXAC coriolis meter	+/- 5%
Gas outlet	Daniel orifice fitting	+/- 15%
Tembungo B		
Liquid leg	Smith PD meter (Custody transfer)	+/- 1%
Gas outlet	Daniel orifice fitting	+/- 10-20%
Humble		
Oil leg	Smith PD oil leg, Micro Motion	+/-1%
Water leg	Coriolis meter	+/- 1%
Gas outlet	Daniel orifice fitting, Stork ultrasonic	+/-1,5%
Luna Modular		
Liquid leg	Stock tank and sampling	+/-5%
Gas outlet	Daniel Orifice fitting	+/-15%

Table 7 REFERENCE MEASUREMENT.

Rabi	Density	Viscosity
OIL	sg 0,854 / API 34.1 at 153C	11 cP at 40°C, 6 cSt at 60°C
GAS	NA (natural gas)	NA (natural gas)
Production WATER	sg 1,19 at 40°C	-
Tembungo B		
OIL	sg 0,843	2,66 cP at 25°C
GAS	NA (natural gas)	NA (natural gas)
Production WATER	1,15	-
Humble		
OIL	MW 264, sg 0,9093 at 60°F API 23,96	36,3 cP at 1000 psi / 80°F
GAS	Methane MW 16,06	NA (natural gas)
Production WATER	Brine	-
Luna Modular		
OIL	sg 0,808, API 42,95	2,1 cP at 39°C
GAS	0,67 kg/m^3	-
Production WATER	60550 ppm salinity	-

Table 8 FLUID PROPERTIES.

Main Index

North Sea FLOW Measurement Workshop 1995

Paper 17:

DEVELOPMENT AND TESTING OF THE "MIXMETER" MULTIPHASE FLOW METER

4·3

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DEVELOPMENT AND TESTING OF THE 'MIXMETER' MULTIPHASE FLOWMETER

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September 1995

SUMMARY

The MIXMETER multiphase flow meter has been developed over the last three years by Imperial College and SGS Redwood through a project sponsored by the UK Offshore Supplies Office (OSO) and a consortium of oil companies.

This paper traces the development of MIXMETER from pre-project studies through to tests of a 3" (76mm) laboratory prototype on the Imperial College WASP multiphase flow rig and on the National Engineering Laboratory (NEL) multiphase flow facility. Test results from NEL are presented.

A 4" (100mm) field prototype has now been built and will undergo trials at an oilfield test site early in 1996.

Performance to date is extremely encouraging, patents have been applied for and discussions are in hand with potential commercial manufacturers.

GENERAL DESCRIPTION

MIXMETER comprises a specially developed static mixer (homogeniser), a dual energy gamma phase fraction instrument and a second gamma instrument for cross correlation velocity measurement. Velocity is also determined from the mixer differential pressure.

A schematic of the laboratory prototype is shown in Figure 1.

MIXMETER DEVELOPMENT

Background

The commercial advantages to the industry of a proven multiphase flow meter have been well documented in the past:

Reduced need for separate well test lines

Reduced need for test separators and hence weight saving on offshore structures

Improved reservoir management

Although the potential cost savings for a subsea installation are most striking a meter of sufficiently low price would also find application for topsides and land based installations. A phase fraction meter would also appear to have commercial possibilities in its own right.

Pre-project Studies

By the mid 1980's a number of techniques had been tried and various groups across the oil industry together with some manufacturers were pursuing R&D projects with the aim of developing a metering system. However, it was becoming apparent that there would be no quick and easy solution. Therefore, the UK Department of Energy through the Offshore Supplies Office (OSO) and the Offshore Energy Technology Board (OETB) commissioned two studies in order to review the technical and commercial situation and hopefully to identify a technical route which had the best chance of success in addressing industry requirements.

Both reports were commissioned through Imperial College but other organisations working in multiphase flow were involved (The National Engineering Laboratory, SGS Redwood, AEA Harwell) in addition to potential users, particularly Texaco and Shell.

OETB report OTN 88-195 reviewed an extensive range of methods for mass metering of multiphase flows with emphasis on techniques which would be suitable for eventual subsea application. This report demonstrated the significant advantages of homogenising the flow prior to making measurements and identified a number of measurement techniques which could be expected not only to provide the performance required but also to result in a device which was commercially viable.

The second report, OETB No.OTN 90-175, was a project definition study for a meter based on homogenisation. This confirmed that homogenisation was feasible in terms of the basic physical ability to retain a homogenised mixture of oil, water and gas over sufficient length in a pipeline to allow measurements to be made without at the same time having to use so much energy that stable emulsions would be formed. The report also investigated further the measurement techniques which offered the best opportunity to achieve the desired results.

Techniques selected for further evaluation through an R&D project were:

Multi-energy gamma for phase fraction

Gamma cross correlation for velocity

Alternative methods selected were:

Neutron interrogation for phase fraction

Weighing for mean density

Venturi for velocity

The basic technical key to substantially simplifying the multiphase measurement problem was seen to be to homogenise the components, removing 'slip' such that only three instruments are required to determine the individual flows of the three components. In this case the preferred instruments were three gamma beams; two for oil/water/gas fractions and one for velocity determination.

Due to the success of the primary techniques the alternatives have not been investigated in depth. Initial work using a venturi was halted when the homogeniser pressure drop was found to provide a very good indication of multiphase velocity.

MIXMETER Stage 1

Introduction

The MIXMETER project (Stage 1) was launched in November 1992 to evaluate the above methods theoretically and through laboratory testing with the aim of proving a system and producing a design brief for a prototype meter.

Project policy was controlled by a steering group which comprised representatives from all the sponsoring organisations.

The project was carried out under the direction of Imperial College acting through its consultancy arm, IC Consultants Limited (ICON). The Project Director was Professor Geoff Hewitt.

Overall administrative and financial control was provided by Mr Paul Docx of ICON. Detailed project management was provided by Mr Paul Harrison of SGS Redwood.

Other members of Imperial College were involved, principally Professor George Shires who provided analytical support and Dr Susan Parry who contributed the appropriate nuclear instrumentation expertise.

ICI Tracerco provided general consultancy throughout the project.

SGS Redwood were heavily involved in the homogeniser development and also provided the practical flow measurement expertise necessary throughout the project and particularly related to the rig trials.

Funding was obtained from Brasoil, British Gas, Mobil, Texaco, Total and the OSO and the work ran through a 22 month period.

This first intensive programme resulted in a 3" (75mm) NB laboratory meter comprising:

A specially developed homogeniser/flow conditioner.

A dual energy X-ray/gamma phase fraction meter.

A second gamma device for cross correlation velocity measurement.

The complete assembly is less than 1m in length.

The development of each of the system components is discussed below.

Homogeniser

Background

If the nuclear instruments are to function as required it is essential to provide effective homogenisation to remove 'slip' (gas travelling faster than the liquid components) and to produce an even distribution of the flowing components across the pipe diameter where the nuclear absorption is being determined. This becomes more critical as the width of the gamma beam reduces.

As the gas separates from the liquids very quickly it was realised that traditional in-line mixers which comprise a series of flow separation and twisting elements were unlikely to be successful. A much more abrupt device is required.

SGS Redwood had developed such a mixer based on the twin cell rotation principle and this had been successfully tested in two phase flow by SGS and during an earlier development project at the National Engineering Laboratory.

This SGS Redwood plate type (MkI) mixer (see Fig 2) has also been evaluated by Christian Michelsen Research (CMR) and was found to provide good flow conditioning over a wide range of two phase flows.

Development and Testing

A streamlined version of this mixer (MkII) was developed by SGS for MIXMETER (see Fig 3). This was refined following initial tests on the Imperial College WASP rig. Final comparative tests confirmed that the MkII design was superior to the MkI and to a commercial Statiflo mixer in terms of its ability to condition two phase flows.

Tests were carried out with horizontal flow as is the case for all tests to date and air/water only was used at this stage.

In early trials a broad gamma beam from an Americium source was used with two detectors to determine the vertical distribution of liquid after the mixer. Later work used a fine beam scanning gamma densitometer to measure water hold-up across the pipe downstream of the mixers.

Comparisons were made of a number of characteristics but the basic requirement was for a mixer which would give reliable homogenisation at some defined downstream position where the dual energy instrument would be located. The homogenised region is also required to extend further downstream to a position where the single energy gamma instrument would be installed for cross correlation velocity measurements.

A key parameter therefore is the centreline liquid hold-up as it was planned to use a narrow gamma beam across the centre of the pipe for the measurements. Fig 4a compares the centreline liquid hold-up with the homogeneous hold-up calculated from rig figures. The superior performance of the MkII mixer is clear, producing a centreline hold-up at 4D downstream of the mixer very close to the homogeneous value. Also, the higher correlation coefficient, r, indicates more consistent performance than the other designs.

At 8.3D downstream of the mixer (Fig 4b) the liquid has begun to drop out but homogeneity is still better than the other designs and performance is more consistent. This was considered adequate for the cross correlation measurement at this point.

The above tests were carried out over a range of total velocities from 2m/s to 6m/s. However subsequent system tests indicate that the mixer will continue to work well down to velocities of 1m/s.

Fig 5 compares the pressure drop for the three designs and it can be seen that the MkII is the most efficient.

The MkII design was therefore selected for system tests of the 3" laboratory meter and has now been carried forward into the 4" field prototype.

Dual Energy Gamma Phase Fraction Meter

Source Selection

Previous studies by others Ref (1) had indicated that Americium 241 (59keV) and Caesium 137 (661keV) would provide a good working combination and these sources were selected for initial evaluation. However, during initial tests this combination was found to be much too susceptible to error due to its extreme sensitivity to very small errors in counting or calibration.

A detailed theoretical study was performed and it soon became clear that the key factor is not the simple difference between the energy levels but the difference between the absorption ratios for oil and water. This is illustrated by Fig 6 and it can be seen that the system is relatively unaffected by the high energy selected which simply needs to be greater than about 100keV. The low energy however should be as low as possible and at 59keV Am241 was simply not low enough. These conclusions were confirmed by static testing. An alternative to 59keV Am241 was required and a range of alternative isotopes and energy levels were assessed.

The problem is illustrated by Fig 7a which shows the very narrow working area afforded by the Am/Cs combination.

The use of the lower energy of Am at 18keV was considered impractical due to its limited penetrative power. Barium has a peak at 30keV which could have been used in combination with one of its other peaks at 302 or 356keV. However the Barium spectrum is fairly complex and 'full' which would have resulted in further difficulties with background correction and count rate limitations. Barium is also relatively expensive and supplies are limited. It was finally decided that the best option was to use the two energies of Cs 137, 32keV and 661keV. Advantages of this choice are seen to be:

> The lower energy has sufficient penetrative power to traverse liquid filled pipes of diameters typically used for flowlines without the need to use unusually high strength sources. (Special 'windows' in the tube wall are seen as unavoidable)
>
> The use of both energies from the same source removes any doubts regarding differences between fluids 'seen' by the two beams.
>
> Caesium 137 is a relatively common isotope and readily available.
>
> The Cs 137 spectrum is simple with only two peaks.

Fig 7b shows the improvement in working area available if Cs 137 (32keV/661keV) is used.

Calculation Method
As it has no retained volume the mixer mixes only spatially and not temporally and therefore in most multiphase flow situations and particularly in slug flow the density of the flowing fluids passing the instruments changes rapidly (this allows the cross correlation system to function).

Due to the exponential nature of photon absorption, counting the activity detected over a long period when flow is fluctuating does not give a correct indication of the average density. A technique was therefore developed where counts are collected over a series of very short periods (dwell times), between 5ms and 30ms. These measurements are collected over a 'measuring period' during which several thousand individual counts are made. These counts are then sorted into 10 or more bands and determinations are made on individual average band values before calculating average values for the measurement period.

This routine was developed theoretically using data obtained from initial tests on the WASP rig. It has been tested successfully over a very wide range of flow conditions on WASP and at NEL and shows negligible sensitivity to the statistical errors which can be associated with gamma counting.

Source Size
Cs 137 is normally supplied in stainless steel capsules which cut out the majority of the 32keV emissions. Special 'thin window sources' are therefore required. However, the 661keV peak remains considerably larger than the 32keV peak and for the system to operate well the empty pipe counts should be approximately equal. Detectors used are relatively standard sodium iodide (NaI) photomultiplier tube type. The correct peak balance is achieved by specifying a thinner crystal which allows many of the 661keV photons to pass through undetected whilst allowing capture of most of the 32keV emissions.

The power of the source must be carefully selected so as to provide sufficient counts in each peak over the very short dwell time when the pipe is full of water but not to exceed the maximum total count rate which the detector can accept when the pipe is empty. The need for this balance will put a practical limit on the largest pipe diameter for which MIXMETER is suited of around 150mm to 200mm. High power sources are not necessary. For the 3"(75mm) meter a 50mCi is used and a 100mCi source will be adequate for the 4"(100mm) meter.

Beam Geometry

A single vertical beam was chosen. Collimation was found to be critical as is background (scatter) correction. Suitable arrangements were determined through a series of static tests using flat sided test cells, perspex pipe sections and, to study the effect of fluid distribution, a layered test cell which allows oil, water and air samples to be positioned in any order in the gamma beam. Accurate background correction was achieved using a combination of fixed, proportional and measured values to subtract from the measured peak values.

Cross Correlation Velocity Measurement

Cross correlation of density measurements between one of the dual energy sources/energies and a second downstream instrument should in theory provide a perfectly adequate measure of velocity of the bulk fluid once the slip has been removed by the homogeniser.

To avoid the need for a second set of 'windows' in the pipe wall at the downstream position the absorption of the high energy 661keV is used. It is important to use the same energy range and general geometry at both positions to avoid introducing errors.

Maximum separation of the instruments was determined using the fine beam traversing gamma device to confirm persistence of flow conditioning downstream of the mixer. Mixing effects were found to persist to about 10D. However, to ensure good performance for the 3" laboratory meter 500mm (6.5D) was chosen. The 4" field prototype has a separation of 600mm (6D).

To provide a signal for correlation it was convenient to use the same dwell time as for the dual energy calculations. The correlation is therefore performed on two series of counting figures with dwell times typically of 10ms over a 40 second measurement period. The combination of dwell time and instrument separation gives a fairly coarse measurement step. Also the instantaneous velocity of the homogenised fluid can vary by a factor of at least two during slug flow. Individual velocity measurements therefore exhibit a fair degree of scatter. However, accurate results are obtained by averaging successive measurements and as few as 10 are found to produce acceptable results.

Differential Pressure Velocity Measurement

The MkII SGS mixer has been found to have the added advantage that pressure drop correlates evenly and precisely with the product of the total velocity and the liquid velocity. This relationship holds over all test conditions run to date on WASP and at NEL and provides a second determination of velocity to compliment the cross-correlation measurement.

This redundant measurement is used to reduce the overall uncertainty of velocity determination.

Also, more importantly, in situations where the cross correlation system will not function due to lack of sufficient density perturbations in the flow the differential pressure velocity continues to be valid, extending the range of the instrument.

NATIONAL ENGINEERING LABORATORY TESTS

Following component development and successful component and system tests on the Imperial College WASP rig the 3" laboratory prototype meter was taken to NEL in September 1994 for more extensive testing.

These tests are described below:

Test Fluids

The test fluids used at the NEL were:

Magnesium sulphate solution to simulate produced water.

Stabilised crude oil cut with a little kerosene to produce typical wellhead viscosity.

Nitrogen from a liquid nitrogen supply.

Test Conditions

All tests were carried out with the instrument horizontal. Flow conditions were predominantly slug flow though entering the stratified and annular conditions at the extremes.

These conditions have been selected as being most common and also possibly the most difficult to work in. They do not indicate any perceived limits of operation.

Tests were carried out using water/nitrogen, water/oil/nitrogen, and oil/nitrogen.

Total velocity was varied between 0.75 and 7.7m/s.

Liquid fractions were from 5 to 85% and water/oil ratios from 6 to 0.1 in three phase tests.

The test point matrices are shown in Figs 8 and 9.

All tests were carried out at a nominal pressure of 10bar and at ambient temperature.

All MIXMETER results are calculated from a maximum of 400 seconds of data.

The instrument was calibrated at Imperial College CARE near Ascot prior to shipment to NEL and no changes were made to calibration constants throughout the tests.

Errors quoted below are relative errors and are not based on maximum or total fractions.

Results

Cross Correlation Velocity

Cross correlation results for all runs are plotted against rig total velocity in Fig 10.

Predicted total velocity is plotted against Rig total velocity. An average error of -0.67% is obtained over the whole range with a standard deviation of 7.14%.

There is still clearly some remaining statistical scatter due to the 400 second limit on data collection time. For longer determinations errors will be reduced further, certainly to within 5% and possibly to the order of 1%.

Differential Pressure Velocity

Fig 11 shows the mixer differential pressure plotted against the square of rig total velocity multiplied by the dual energy liquid fraction.

The fluids involved in each test are indicated and it can be seen that the correlation is not noticeably dependant on the fluid properties.

Fig 12 shows this correlation used to predict the rig total velocity. Average error is -0.04% and standard deviation is 7.17%.

By taking a simple average of cross correlation and differential pressure results and removing one 'rogue' result average error is becomes 0.99% and standard deviation is reduced to 4.22%. Fig 13 shows the relative errors.

Dual Energy Liquid Fraction

Fig 14 shows liquid fraction, determined by adding the dual energy water and oil fractions, plotted against the rig total liquid fraction for all test points. The fluids used in each test are indicated. It can be seen that the data is consistent throughout the range from 5% to 85% liquid.

Figs 15 and 16 show the individual oil and water fractions from all 3-phase runs plotted against rig data. Both plots correlate reasonably with the straight line though there is noticeably more scatter with the oil fraction results.

In addition to the statistical scatter resulting from using only 400 seconds of data a small amount of electronic drift occurred during the tests. The results are found to fall into groups according to test date (tests were run over three weeks).

Fig 15 uses different symbols to distinguish the three groups of data. The effect of the drift can clearly be seen with results 17-21 and 61-63 showing a positive bias. Runs 41-49 are evenly scattered about the ideal line with an average relative error of only 6%.

This problem of drift has been overcome with the purpose built electronics designed for the field prototype.

Conclusion

The test results show that the instrument is capable of giving multiphase velocities and liquid fractions with average errors within the 5% target which was originally set for the project.

This is achieved over run times of only 400 seconds in predominantly slug flow regimes. Scattering will certainly be reduced when running times are extended beyond this limit.

PRESENT AND FUTURE PROGRAMME

MIXMETER project Stage 2 is now well underway and comprises the following tasks:

Detailed design of a 4" (100mm) NB field prototypemeter.

Procurement/construction of the meter.

Rig trials (probably again at NEL).

Field trials at a suitable onshore test site.

The mechanical design and construction of the meter including the pipe wall windows has been carried out by Cambridge Advanced Technologies Ltd. who have also provided the communications electronics and the software. A general arrangement of the 4" meter is shown in Fig 17.

ICI Tracerco have developed stabilised counting electronics and are providing the detectors, sources and source holders.

Although the meter is eventually targeted at subsea applications it is considered essential to prove the device on the surface before advancing to a subsea system. However, the subsea application has been kept in mind during the development so that marinisation planned for 1996 will be a natural progression which will not involve a complete redesign.

Main advantages of MIXMETER are seen as follows:

* Potential for high performance measurement
* Wide application range
* Simplicity - wide use of components which are already field proven
* Compact design
* Use of basic physical principles removes the need for complex calibration or theoretical flow models
* Low cost

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1. Abouelwafa MSA and Kendall EJM "The measurement of component ratios in multiphase systems using gamma ray attenuation" J.Phys.E.: Sci. Instrum, 131 341 345 (1980)

MIXMETER MULTIPHASE FLOW METER

LABORATORY PROTOTYPE

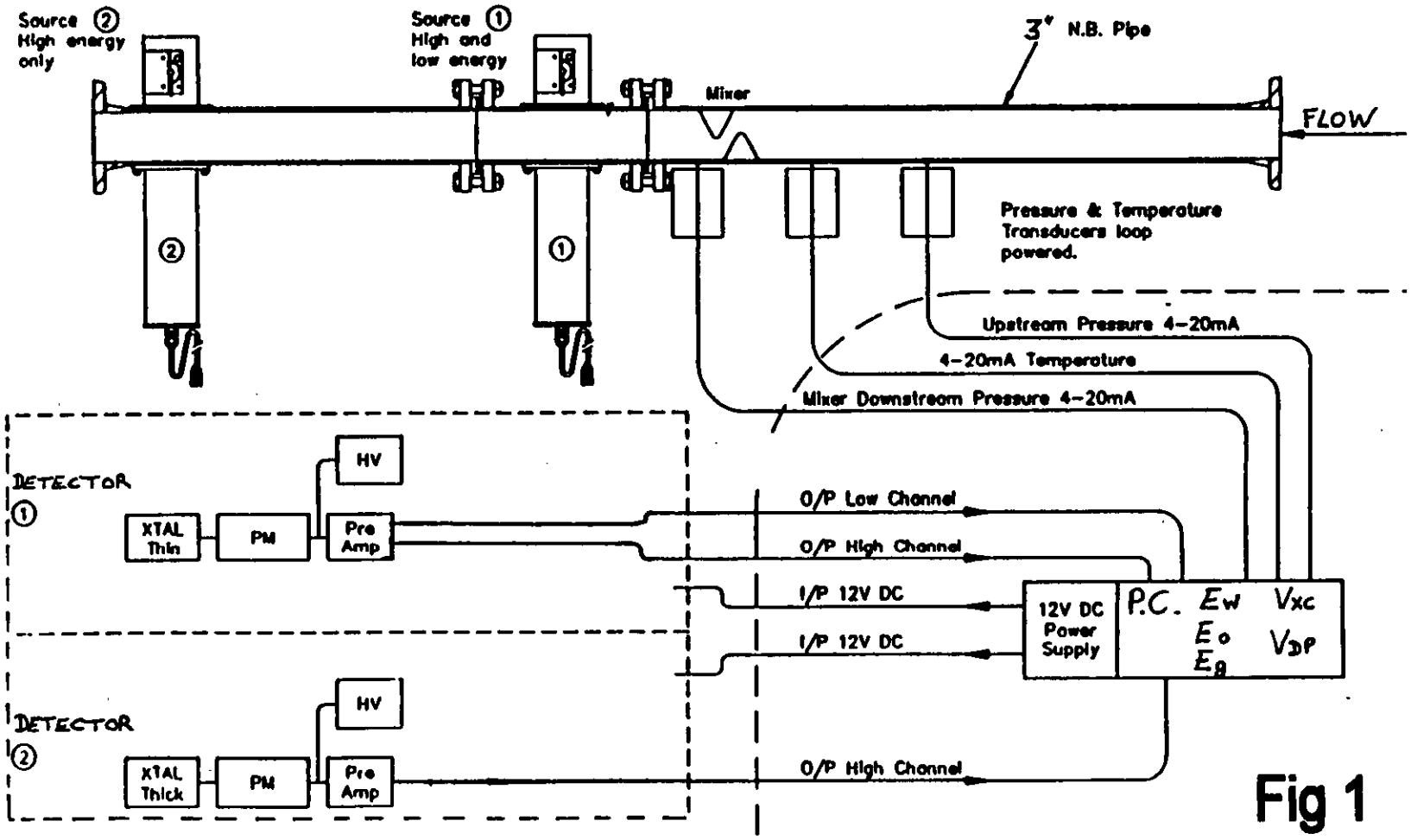

Fig 1

MIXMETER MULTIPHASE FLOW METER

SGS REDWOOD MkI MIXER

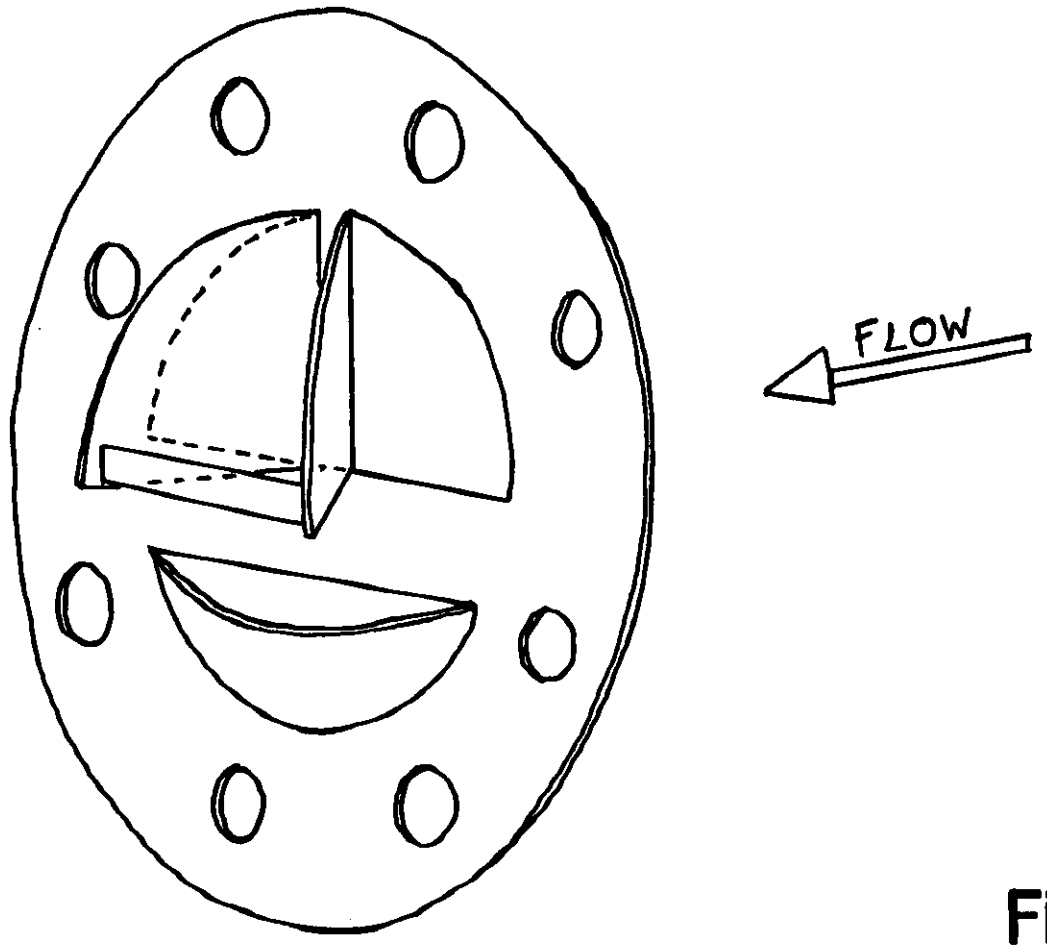

Fig 2

MIXMETER MULTIPHASE FLOW METER

SGS REDWOOD MkII MIXER

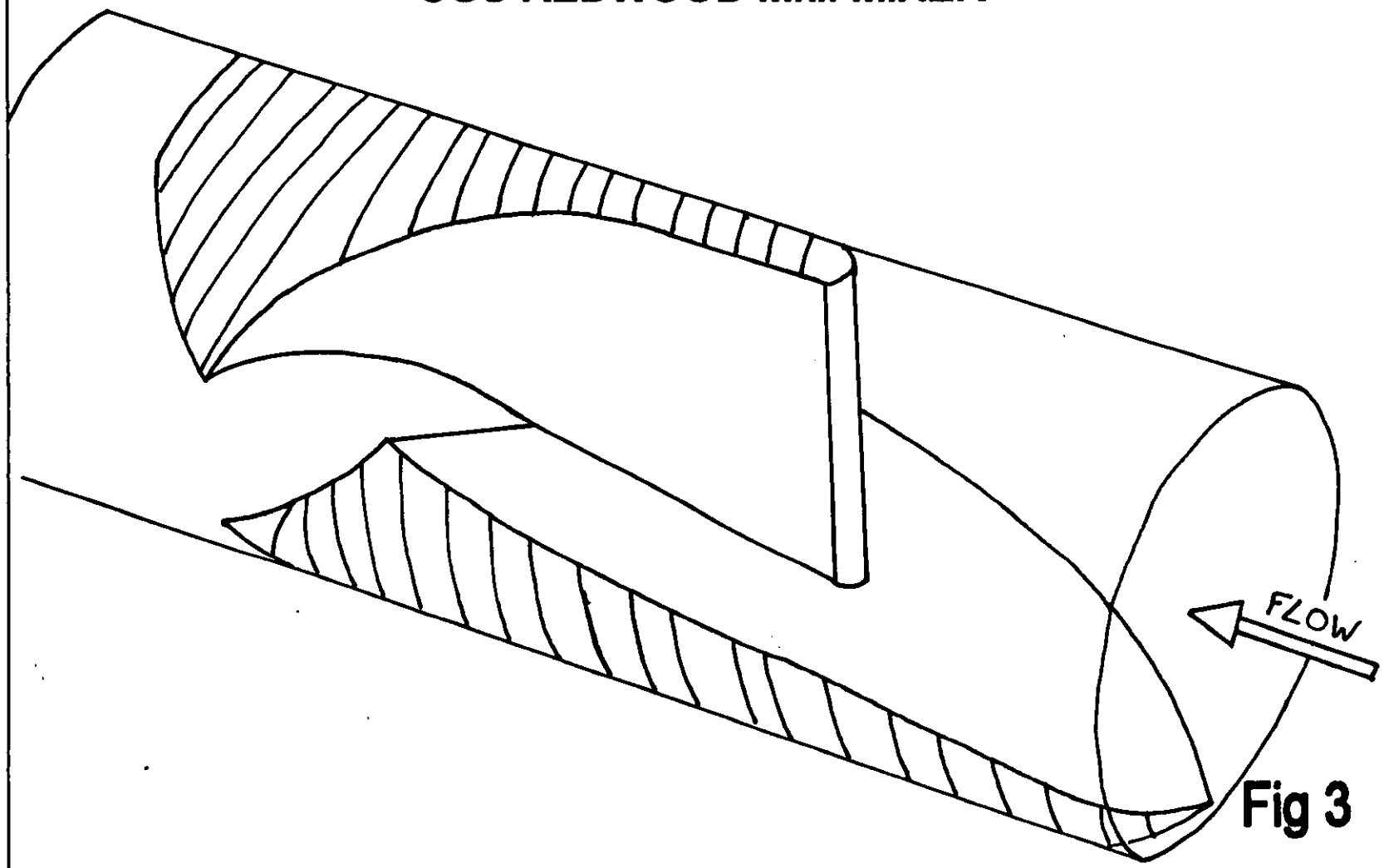

Fig 3

MIXMETER MULTIPHASE FLOW METER

MIXER TESTS - HOLD-UP AT 4D

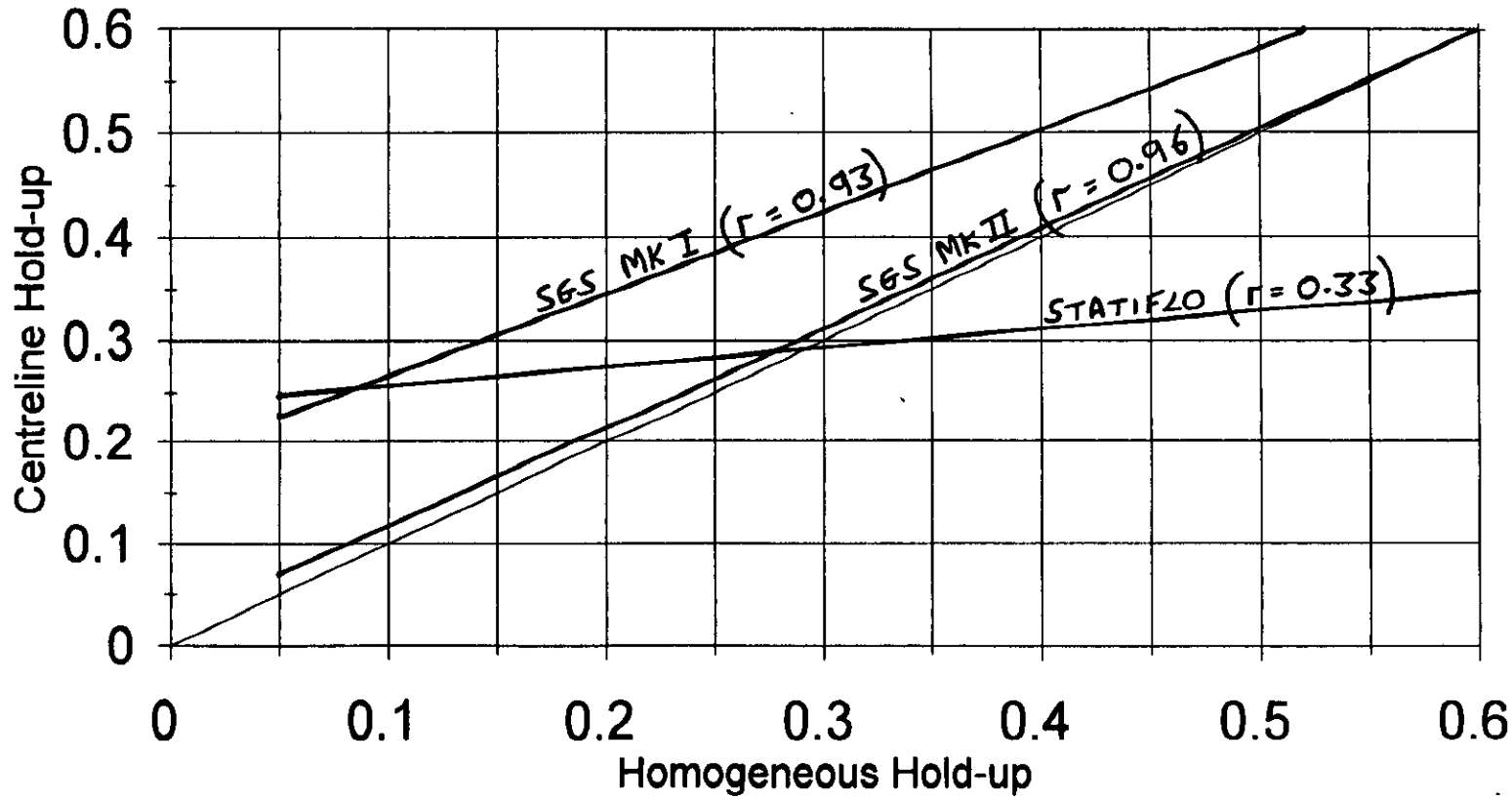

Fig 4a

MIXMETER MULTIPHASE FLOW METER

MIXER TESTS - HOLD-UP AT 8.3D

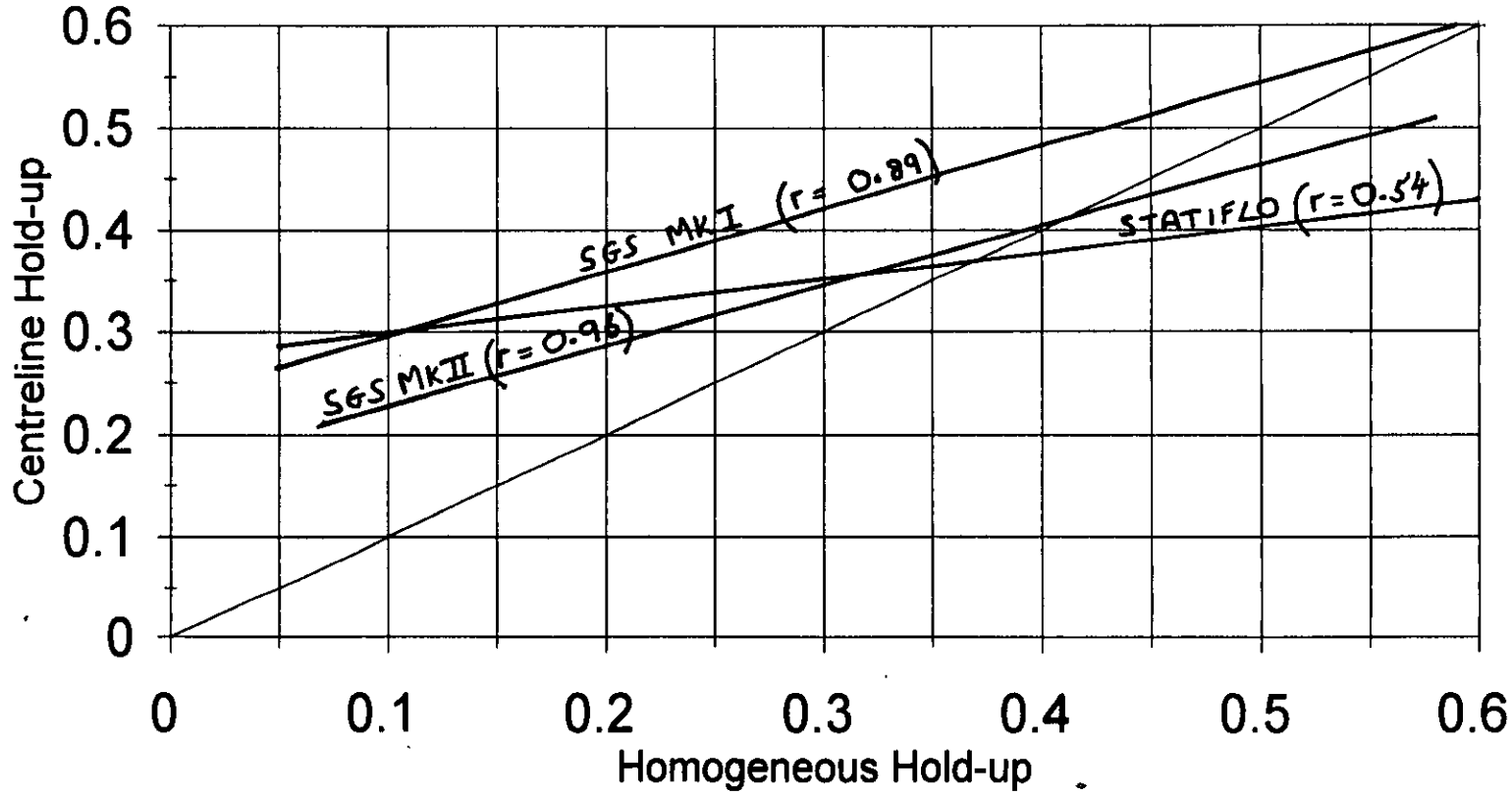

Fig 4b

MIXMETER MULTIPHASE FLOW METER

3" MIXER TESTS - PRESSURE DROP

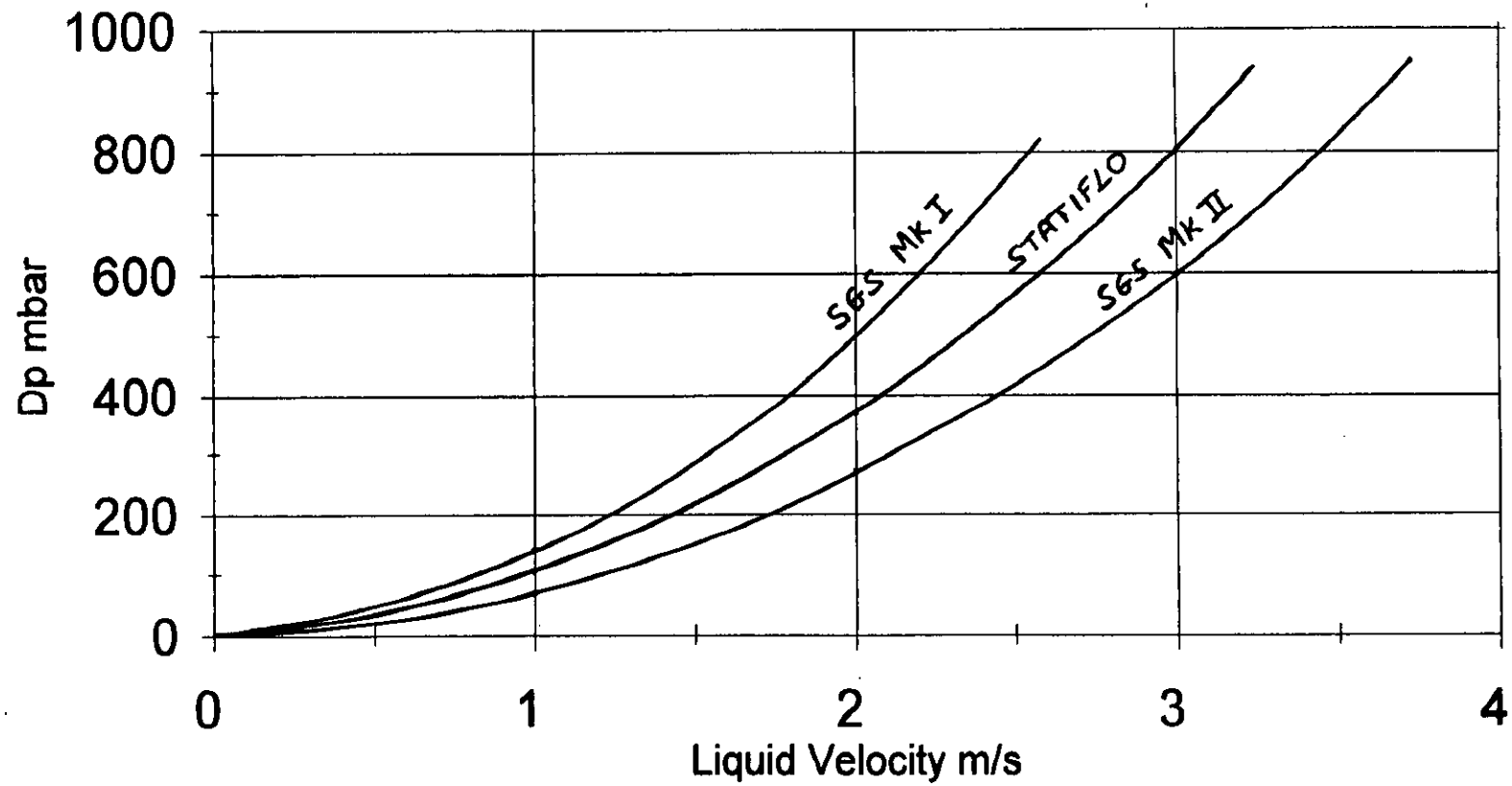

Fig 5

MIXMETER MULTIPHASE FLOW METER

ABSORPTION RATIO vs ENERGY

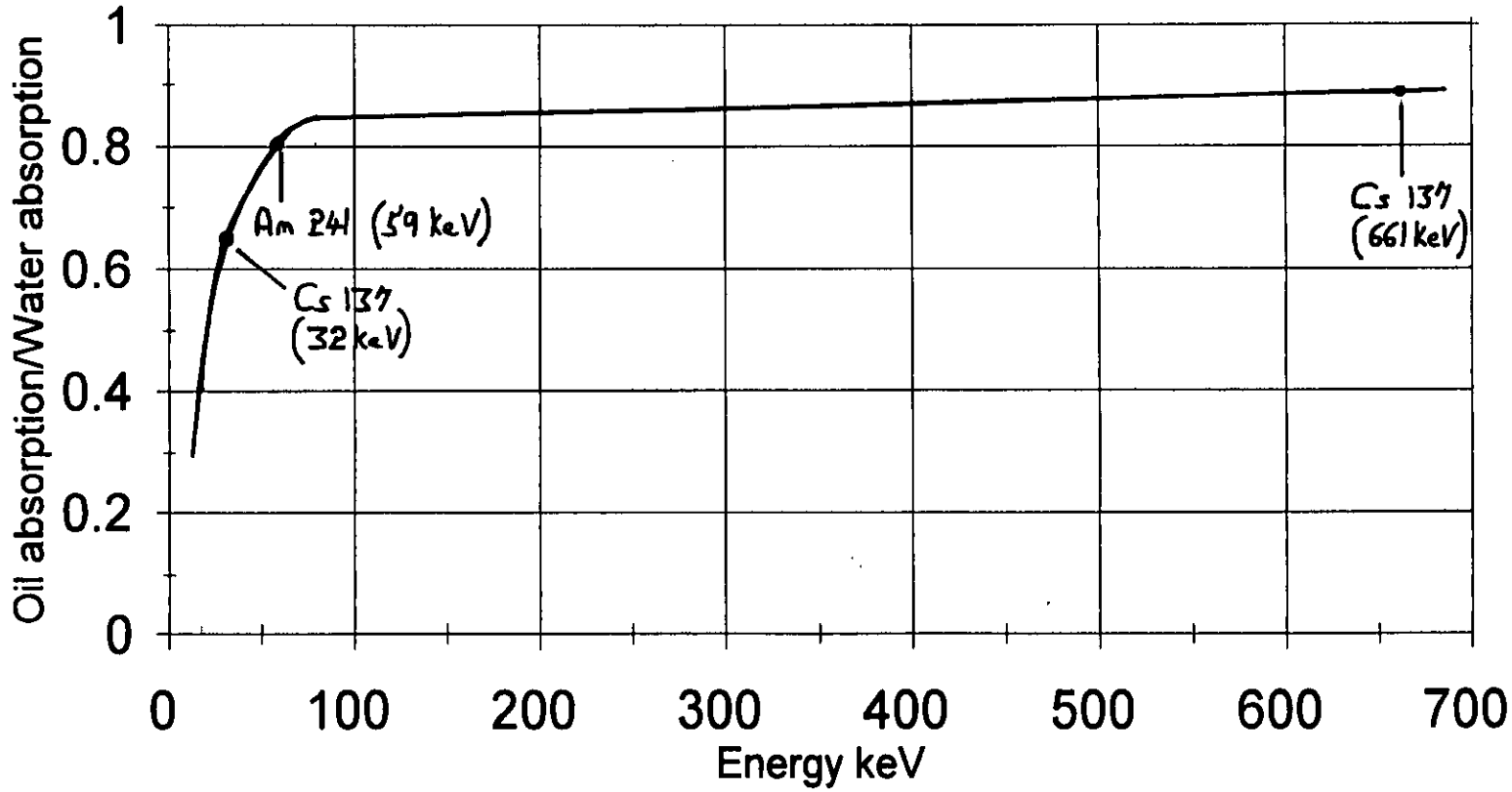

Fig 6

MIXMETER MULTIPHASE FLOW METER

CALIBRATION Am(59)/Cs(661)

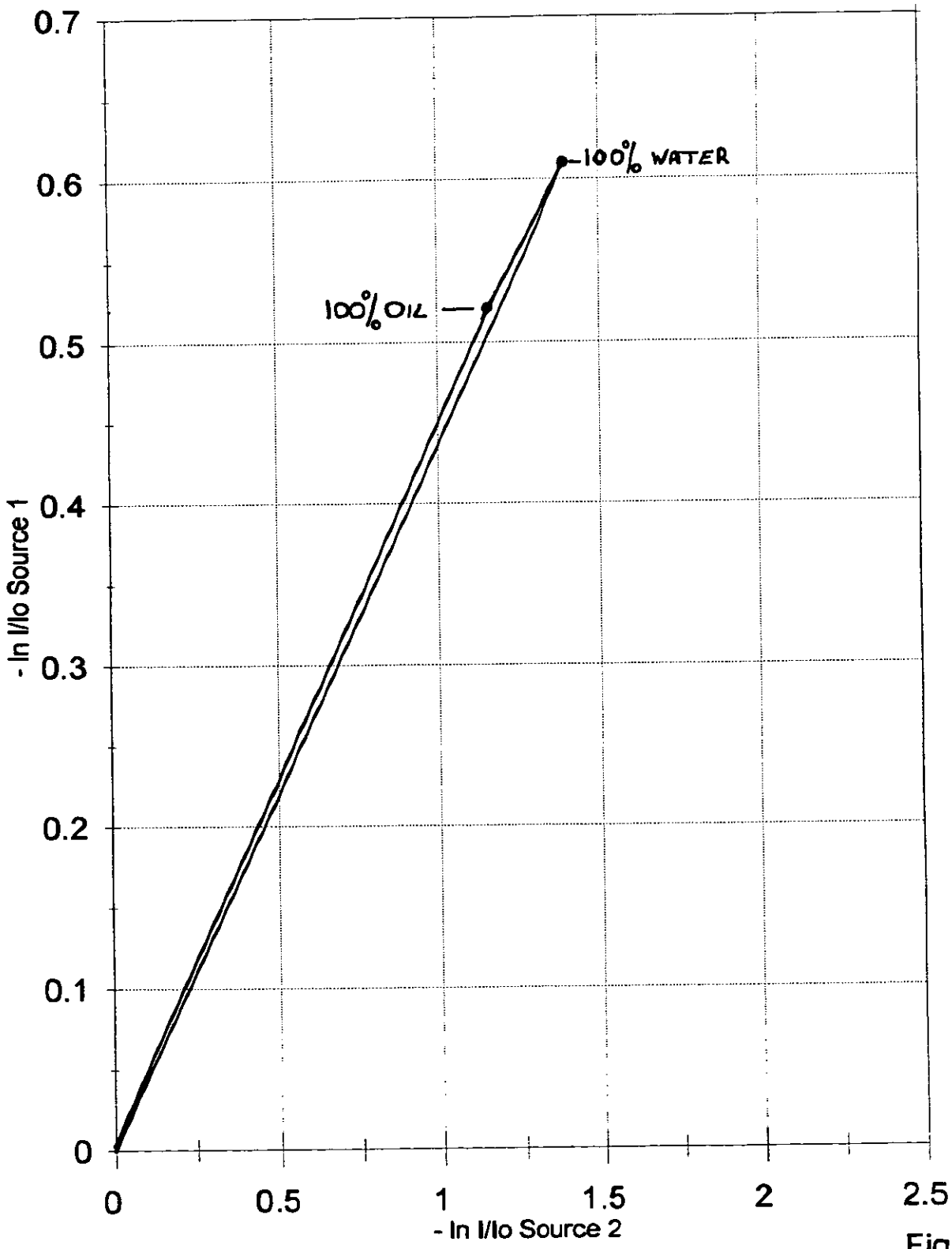

Fig 7a

MIXMETER MULTIPHASE FLOW METER

CALIBRATIONS Am(59)+Cs(32)/Cs(661)

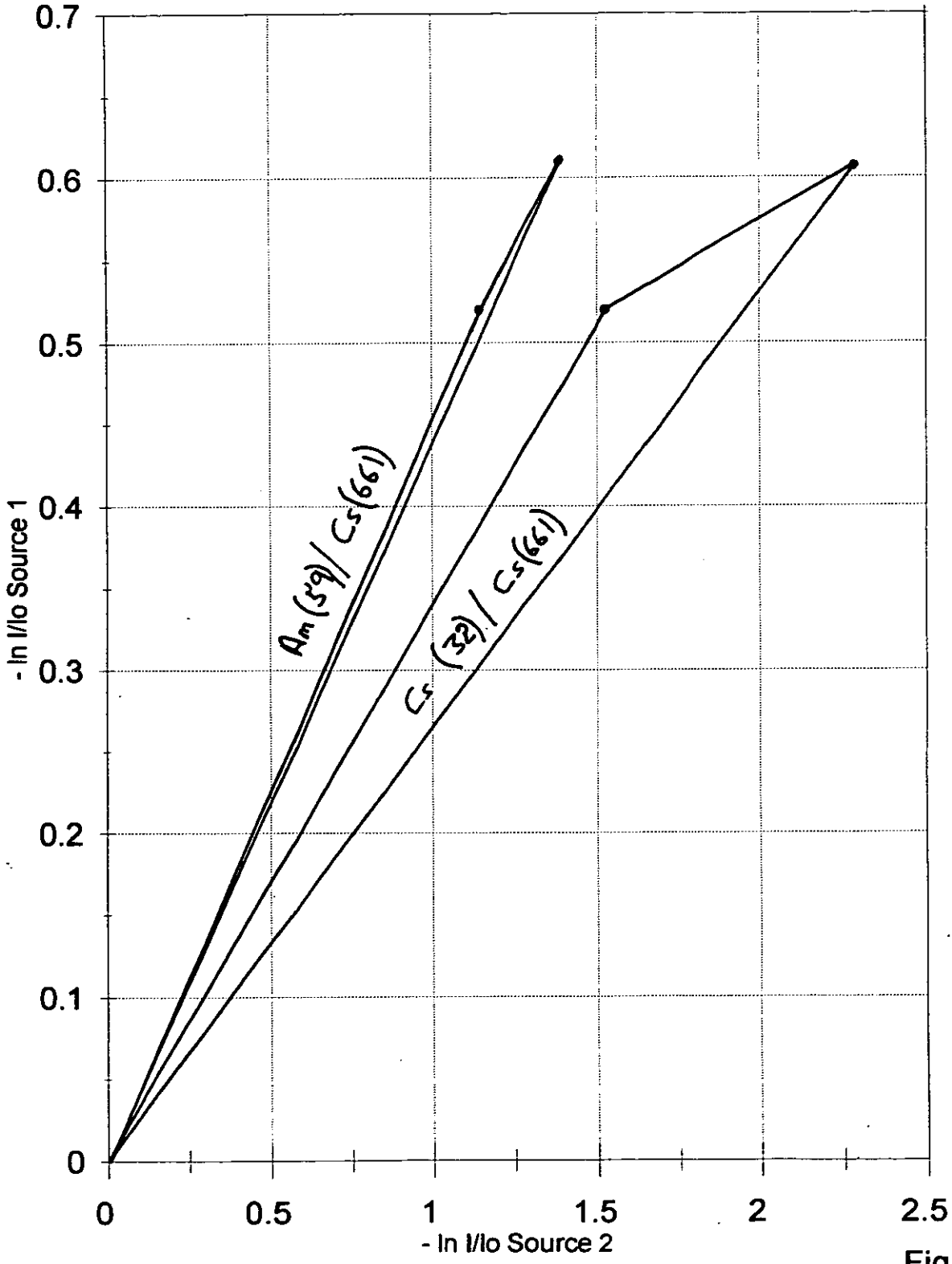

Fig 7b

MIXMETER MULTIPHASE FLOW METER

NEL TESTS - TEST POINT MATRIX

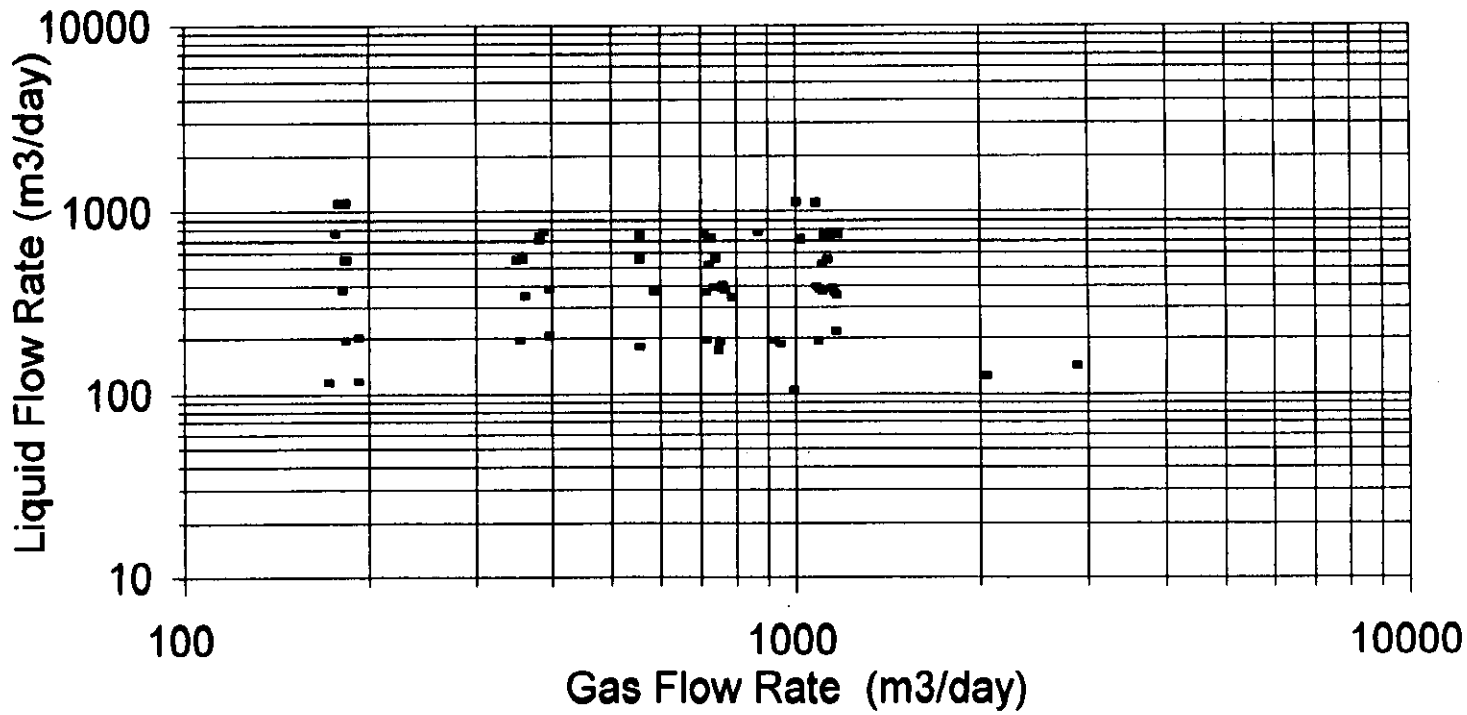

Fig 8

MIXMETER MULTIPHASE FLOW METER

NEL TESTS - MULTIPHASE COMPOSITION MAP

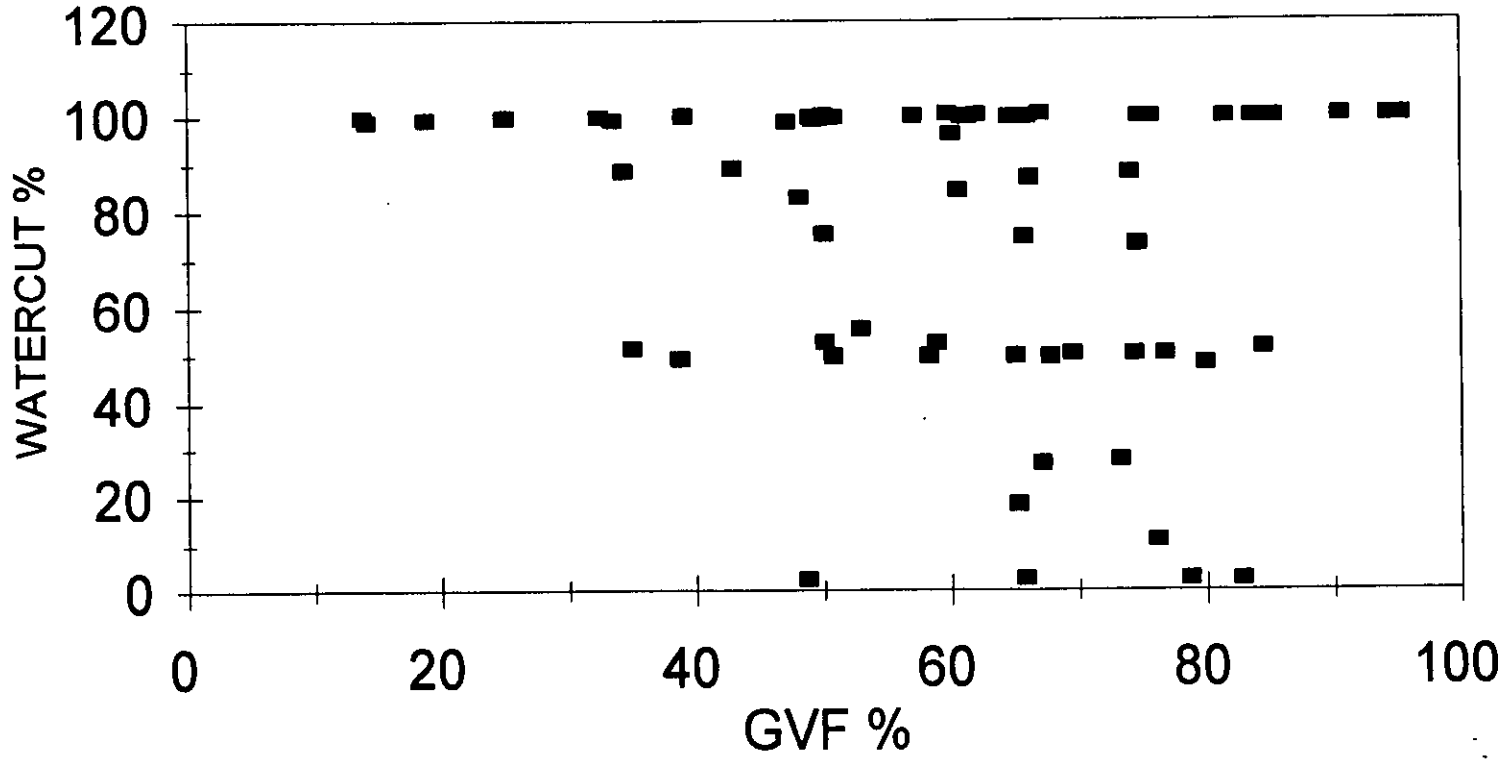

Fig 9

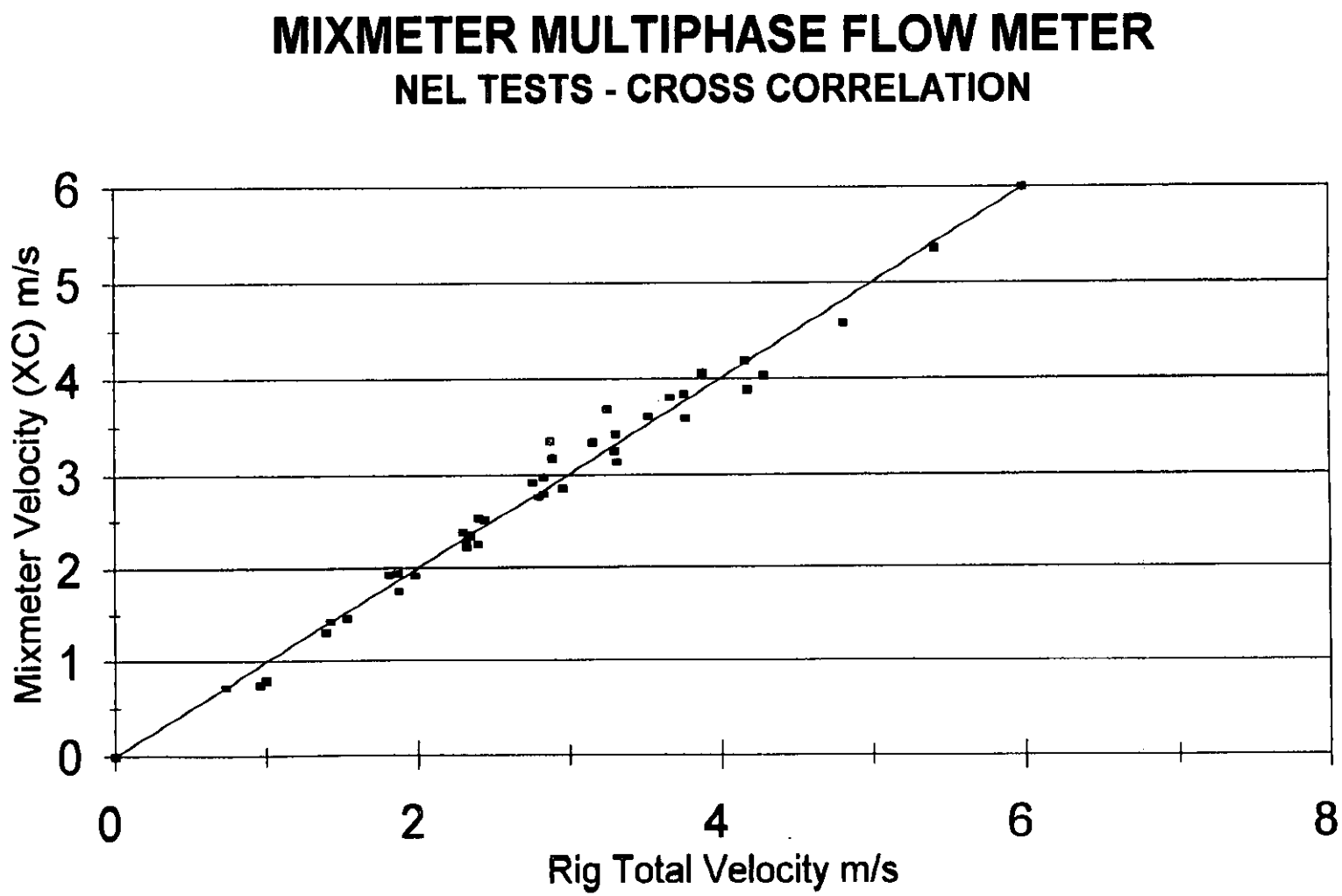
MIXMETER MULTIPHASE FLOW METER
NEL TESTS - CROSS CORRELATION
Mixmeter Velocity (XC) m/s
0
1
2
3
4
5
6
0
2
4
6
8
Rig Total Velocity m/s
All Data Runs 1 - 40

Fig 10

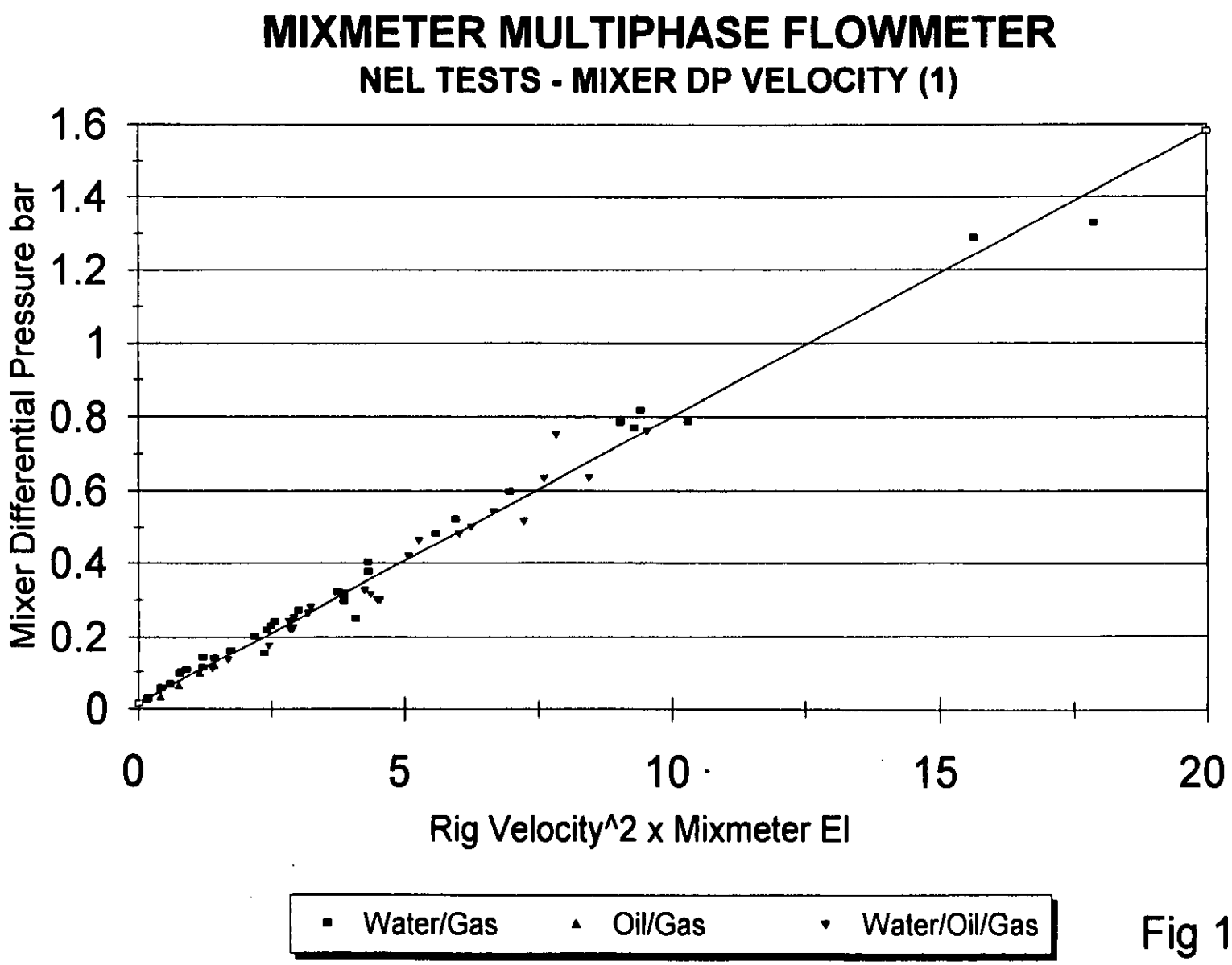
MIXMETER MULTIPHASE FLOWMETER
NEL TESTS - MIXER DP VELOCITY (1)
Mixer Differential Pressure bar
1.6
1.4
1.2
1
0.8
0.6
0.4
0.2
0
0
5
10
15
20
Rig Velocity^2 x Mixmeter EI
Water/Gas
Oil/Gas
Water/Oil/Gas

Fig 11

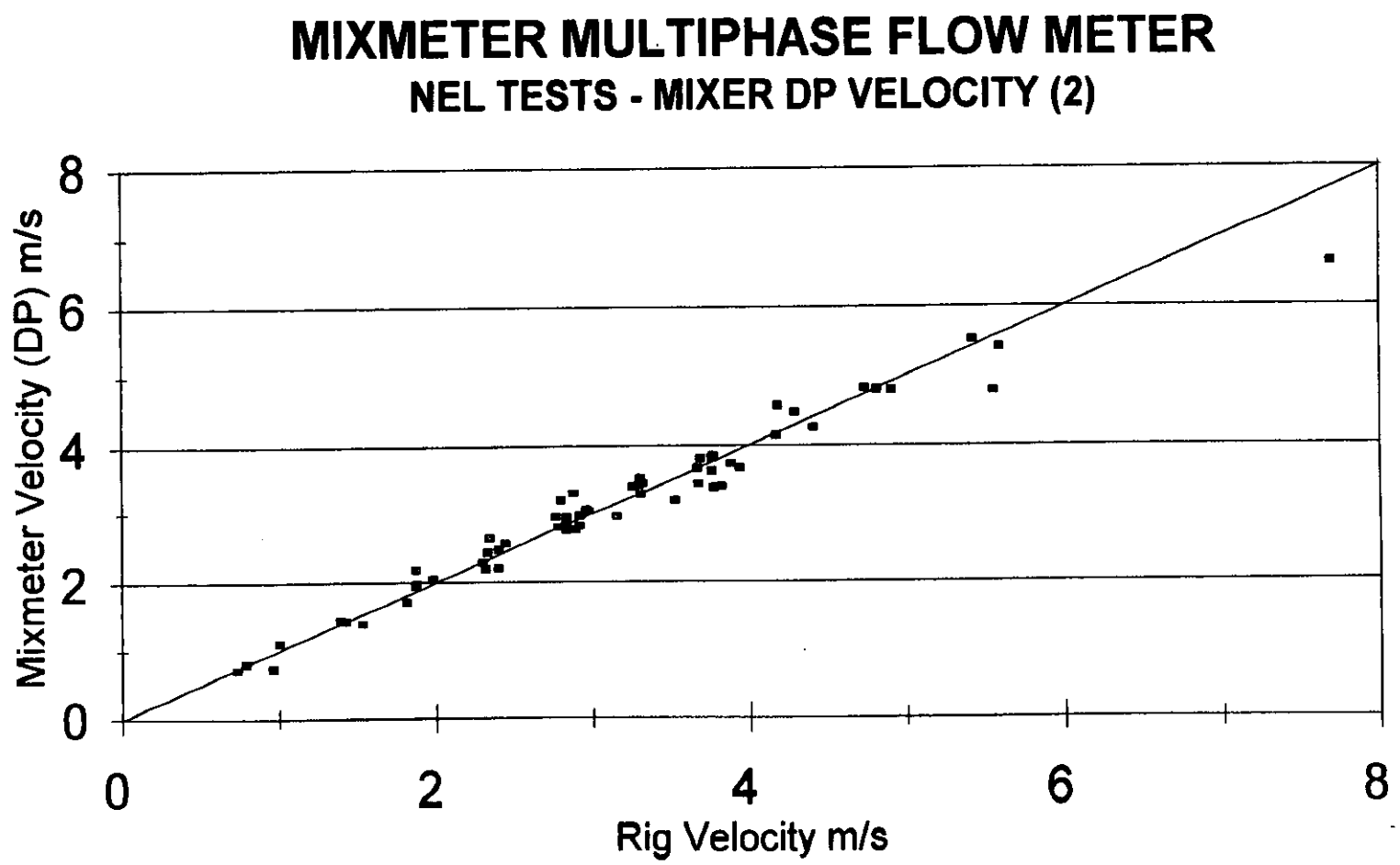
MIXMETER MULTIPHASE FLOW METER
NEL TESTS - MIXER DP VELOCITY (2)
Mixmeter Velocity (DP) m/s
0
2
4
6
8
Rig Velocity m/s
0
2
4
6
8
All Data Points

Fig 12

MIXMETER MULTIPHASE FLOW METER
NEL TESTS - VELOCITY ERROR

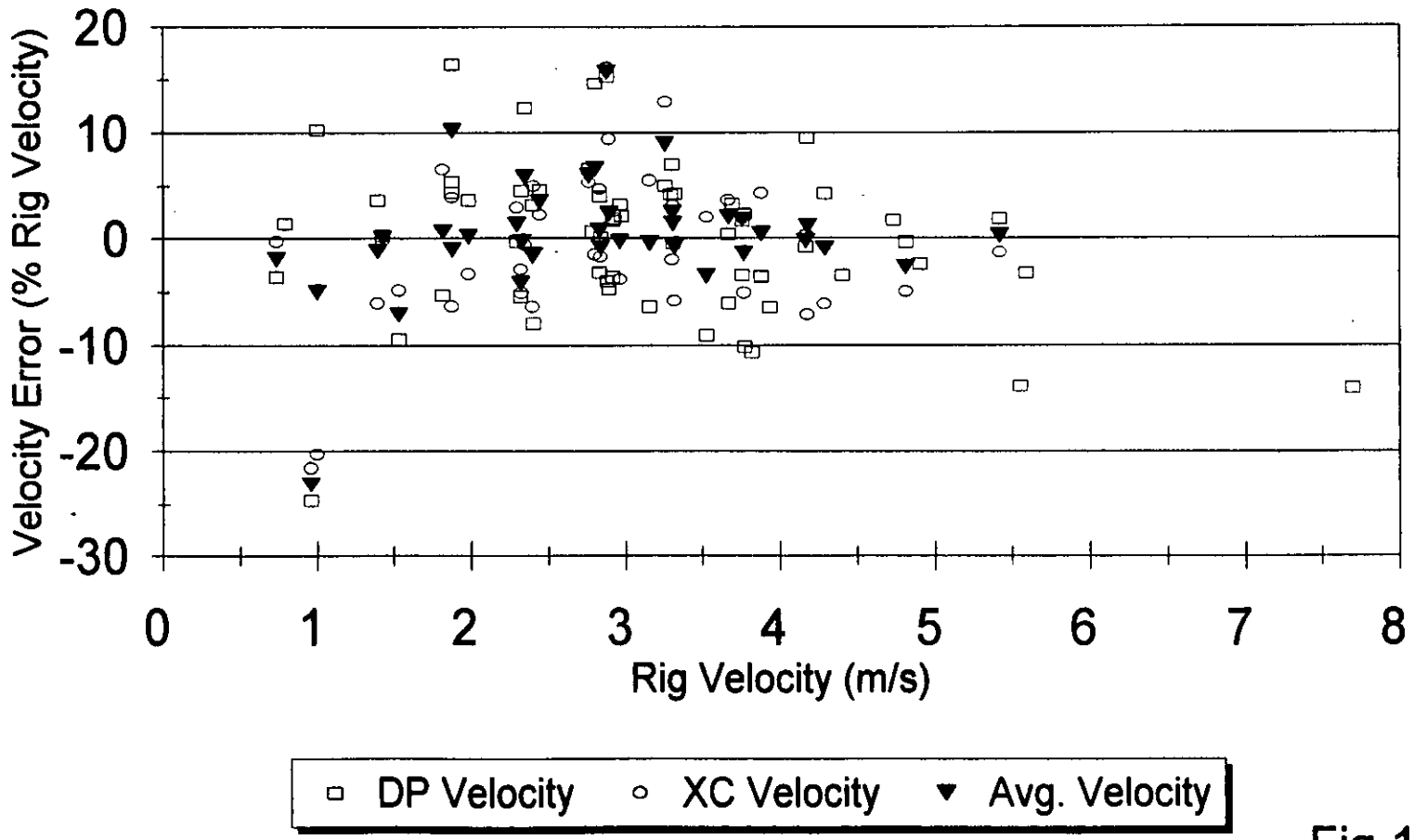

Fig 13

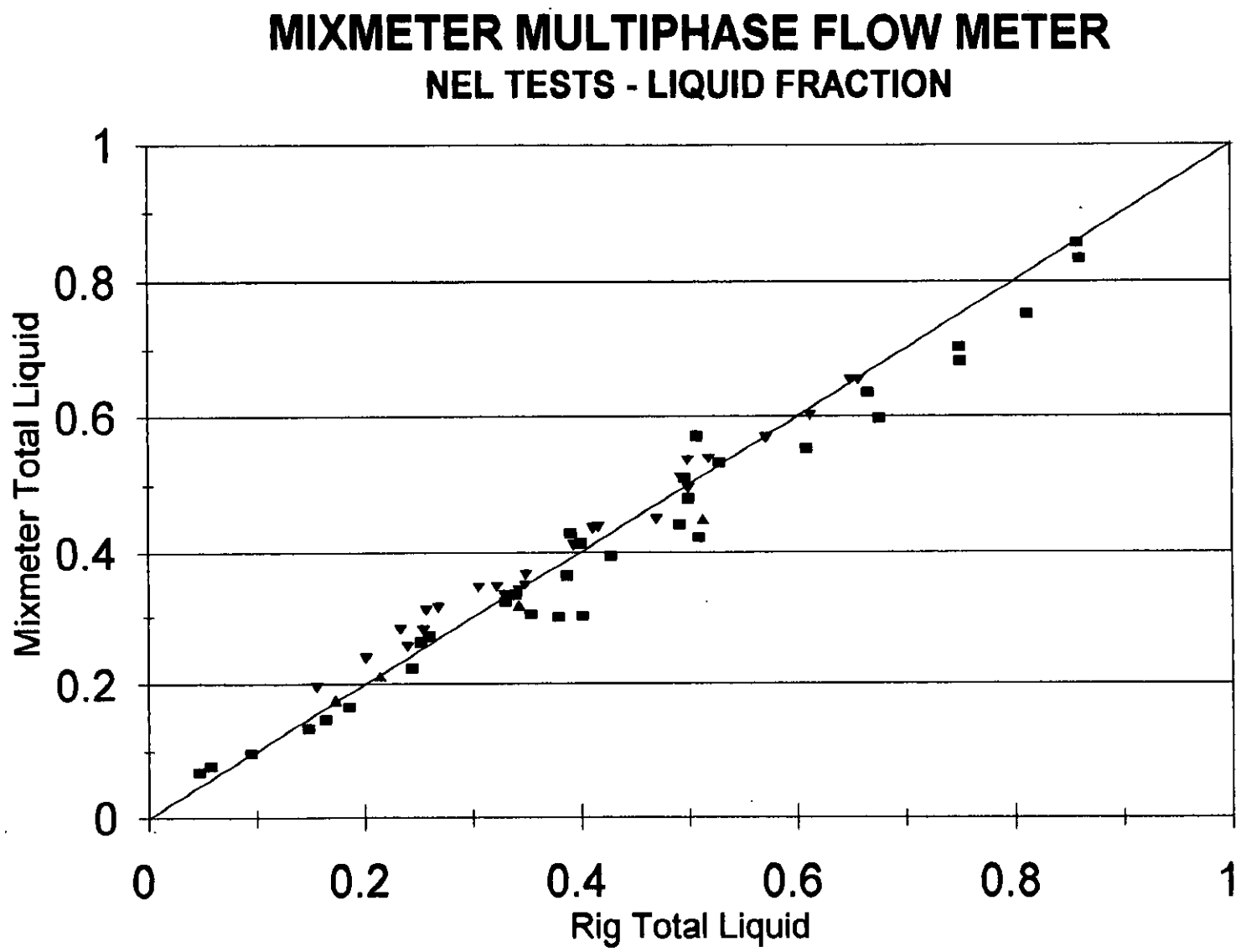
MIXMETER MULTIPHASE FLOW METER
NEL TESTS - LIQUID FRACTION
Mixmeter Total Liquid
Rig Total Liquid
0
0.2
0.4
0.6
0.8
1
Water/Gas
Oil/Gas
Water/Oil/Gas

Fig 14

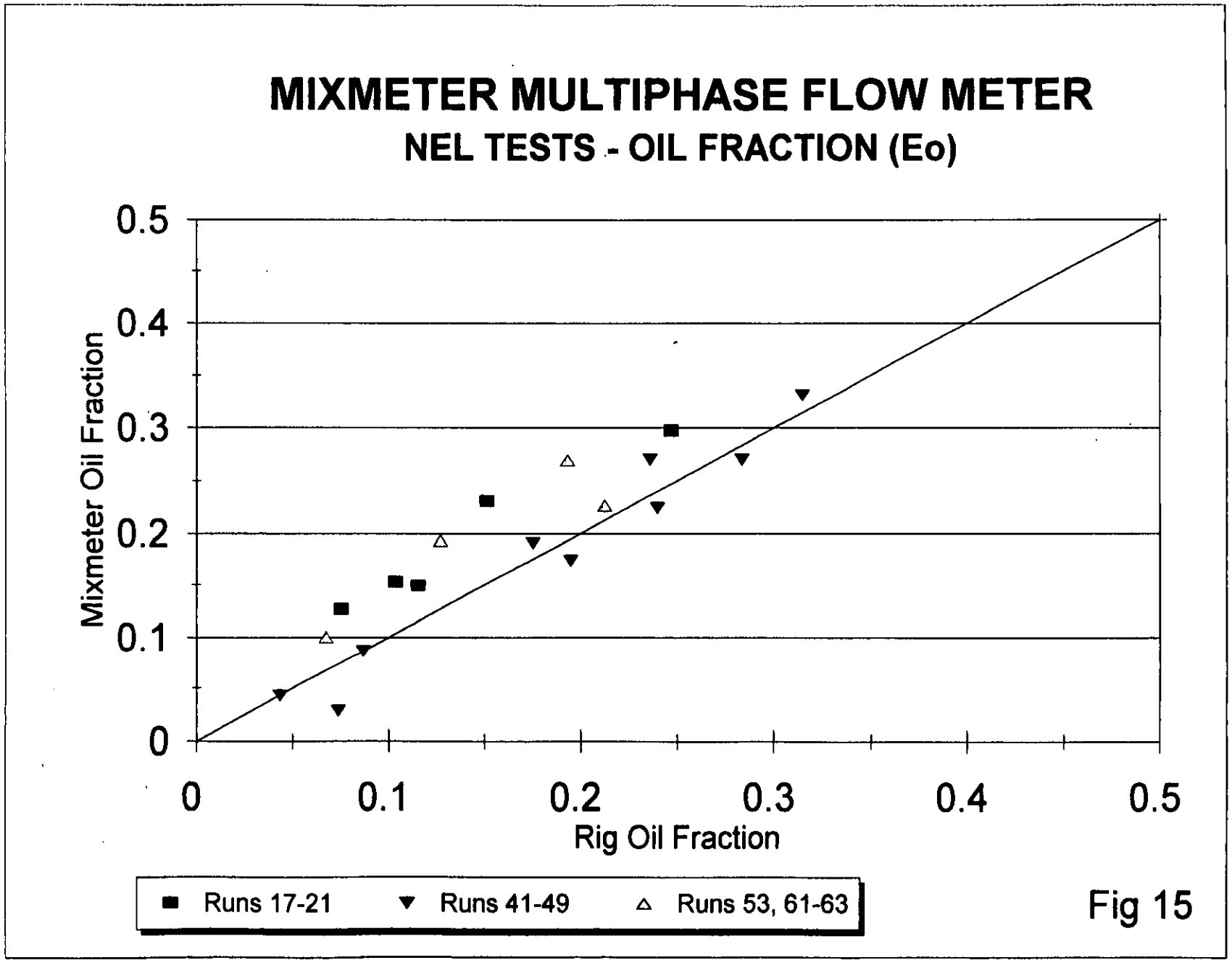
MIXMETER MULTIPHASE FLOW METER
NEL TESTS - OIL FRACTION (Eo)
Mixmeter Oil Fraction
0.5
0.4
0.3
0.2
0.1
0
0
0.1
0.2
0.3
0.4
0.5
Rig Oil Fraction
Runs 17-21
Runs 41-49
Runs 53, 61-63

Fig 15

MIXMETER MULTIPHASE FLOW METER

NEL TESTS - WATER FRACTION (Ew)

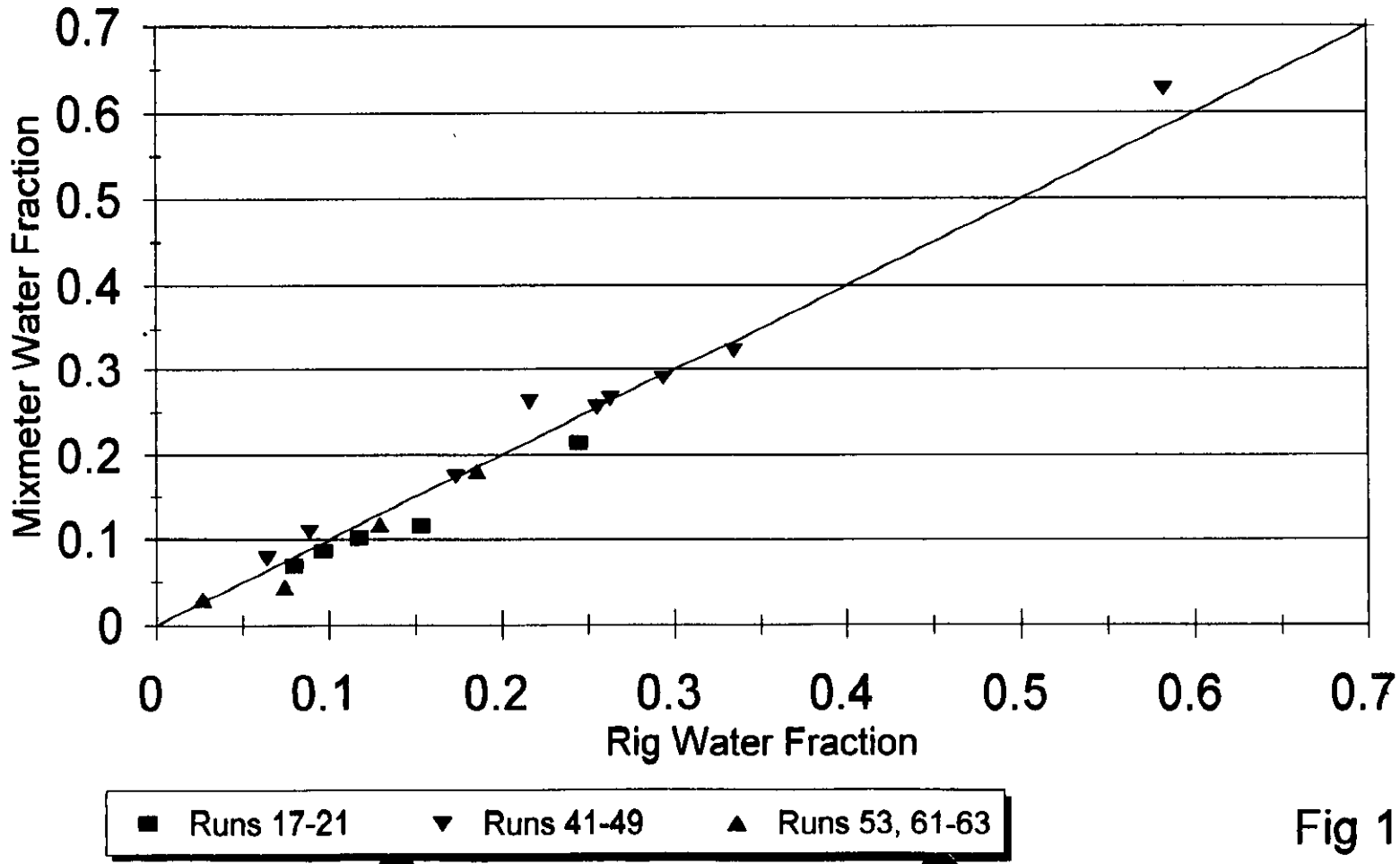

Fig 16

MIXMETER MULTIPHASE FLOW METER

FIELD PROTOTYPE

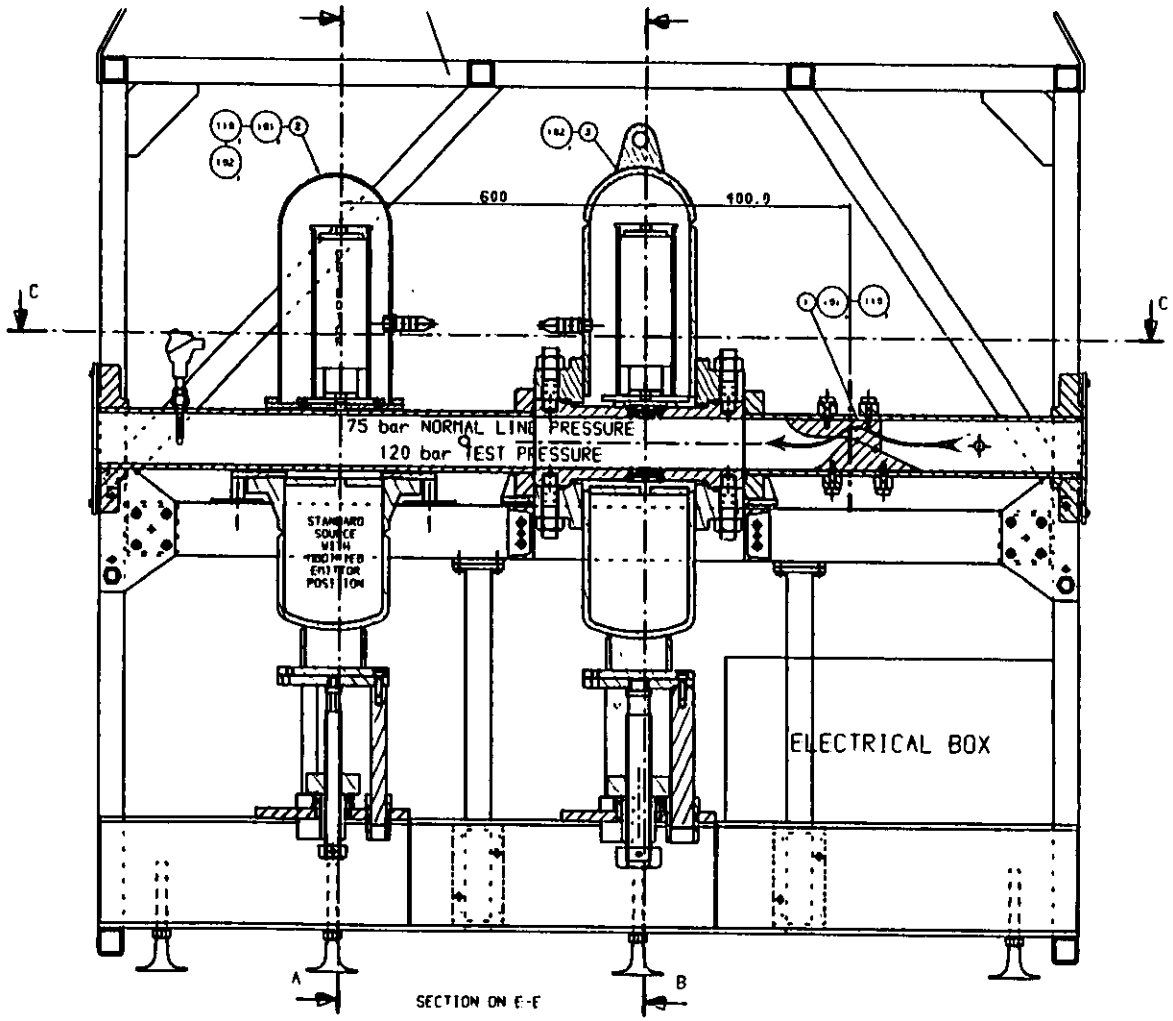

Fig 17

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North Sea FLOW Measurement Workshop 1995

Paper 19:

FLUENTA MULTIPHASE FLOW METER, TESTED AND MARINISED

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FLUENTA MULTIPHASE FLOW METER, TESTED AND MARINISED

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FLUENTA MULTIPHASE FLOW METER, TESTED AND MARINISED

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SUMMARY

This paper describes the technology and principle of operation of Fluenta's multiphase flow meters, for both topside and subsea applications. It also deals with the basis of the design of the subsea multiphase flow meter, and Fluenta's collaboration with Amerada Hess and Kværner FSSL (KFL). The paper further describes the qualification programme and test results obtained at the National Engineering Laboratory (NEL) for this world first installation of a subsea multiphase flow meter, the SMFM 1000, and the benefits and savings this meter will provide to the South Scott field where it was installed in May this year.

1. INTRODUCTION

The ultimate goal for multiphase flow metering has always been to use the technology in a subsea environment. The technology do represents substantial operational and cost savings for topside applications, but being able to implement this technology for subsea applications, means that a higher proportion of proven hydrocarbon reserves found in economically marginal fields can be developed and turned into profitable developments. This is due to the huge savings obtained by eliminating test flow lines and test separators.
In the next couple of years the oil companies have planned to develop a substantial part of their new fields using this technology.

1.1 The background for Amerada Hess Ltd's involvement

Amerada Hess Limited (AHL) is committed to the development of new technology to support and enhance its business activities of finding, developing and producing offshore hydrocarbons. To this end AHL launched a Business Driven New Technology Initiative. This seeks to identify key technology requirements, to initiate R&D projects to fulfil them, and to ensure that the results are commercially exploited.

Amongst the selected areas are health & safety, the environment, drilling costs, mini-field developments, reservoir characterisation/performance and geological basin modelling.

One of the main requirements in the mini-fields area is the development of technology to enable longer and more cost effective satellite tie-backs for small accumulations. This primarily focuses on subsea technology, including separation, and multiphase transportation of produced fluids.

Within this technology thrust, the possibly most significant gap in the armoury of available technology is a reliable non-intrusive subsea multiphase flowmeter.

The applications are endless for a device shown to work satisfactorily in a subsea environment. No more test separators, no more test flow lines. A subsea manifold could contain all the valving required along with a multiphase flow meter, to remotely test each well in turn and still produce via a single flow line back to a remote platform. The ultimate solution would be a gathering platform with subsea satellites scattered over a large area collecting from small fields and providing central processing.

There is no doubt that when the technology is proven the whole face of subsea oil production from marginal fields will change.

1.2 A three stage development project

In a unique joint venture Amerada Hess Limited and Amerada Hess Norge joined forces (Norway supplying the funds and U.K. supplying project co-ordination and monitoring) in backing one of the three phase race contenders.

The project was carried out in three stages.

Stage 1 was completed in 1992. This involved the purchase and testing of the basic fraction meter version of the device. The meter was installed and tested in the new multiphase laboratory at the National Engineering Laboratory in East Kilbride, near Glasgow.

The aims of Stage 1 were to prove that the technology works and determine by experimentation the limitations of use of the instrument. This was successfully done.

In Stage 2 of the project Amerada Hess purchased the three phase flowmeter meter version of the Fluenta device - the MPFM 1900.

The MPFM 1900 was extensively tested at N.E.L. and has now been installed on the AH001 Floating Production Facility. The MPFM 1900 is installed upstream of the test separator between two chokes which will allow direct comparison between the 2 technologies. The signals were integrated into the AH001 Metering Database system, a Eurotherm Maxi-Vis system which provides comparison with the conventional metering system currently installed on the test separator.

The Maxi-Vis Metering Database on the AH001 was reprogrammed to provide the data reporting required to prove the device under real conditions rather than the controlled conditions at N.E.L. This reporting includes duplicated well test reports, one report based on the original test separator metering and a second report using the three phase meter data.

By installing the meter between the two chokes on the inlet pipework to the test separator we were able to simulate either test separator conditions at the three phase meter or increase the pressure closer to subsea pressures.

The AH001 Floating Production Facility (FPF) produces oil and gas from three subsea fields; Ivanhoe, Robroy and Hamish. The well flowrates, GORs, GLRs and oil viscosities are extremely variable and the results so far have reflected this! The meter has been installed to provide long-term evaluation.

The final stage of the project is completed. This was split into two parts. The first was a study of the requirements for a subsea meter. Do we want a meter that can be fitted by divers or ROV? Do we want a complete skid designed including self-calibration checking facilities?. Do we want a single meter on a subsea manifold or one meter per well? What will it cost? After a great deal of thought a report was produced that provided the final specifications for a subsea version of the Fluenta meter, which included for water-continuous measurement up to 100% water in oil.

Part 2 of the project was to build a meter for installation and testing on the South Scott Project.

KFL was selected to work with us on this phase of the project, and they also helped with the funding. The Fluenta electronics were integrated with KFL's fourth generation subsea electronics .

2.0 FLUENTA'S MULTIPHASE FLOW METERS (MPFM)

2.1 Description of the MPFM 1900VI/900VI

Both the MPFM 1900VI and MPFM 900VI are flow meters designed for accurate flow rate metering of the oil, gas and water phases of a multiphase flow, without separation of the well stream. The non-intrusive, real-time instruments require no by-pass line and no mixing device. Both instruments divide the measurements into two; measurements of fractions, and measurements of flow rates.

The fraction part is determined in the same way for both meters: three independent equations are needed and these are obtained by measuring the dielectric constant (permittivity) of the mixture (oil/gas/water) with the capacitance sensor, measuring the same mixture in a gamma radiation path, in which the measured absorption of gamma particles is a function of the density of the mixture measured by the gamma densitometer, and using the third and last equation that the sum of the three fractions will always be equal one.

For water-continuous mixtures an inductive sensor is used instead of the capacitance sensor. The principle is basically the same, except that now conductivity rather than permittivity is measured. Two toroids induce a constant current through the multiphase mixture while the differential voltage is measured across two electrode plates placed between the toroids. As the current is constant, the voltage drop is a measure of the electrical conductivity of the mixture, which in turn is affected by the composition of the mixture (oil/gas/water). The conductivity measured by the inductive sensor is thus a measure of the mixture (oil/gas/water) similar to the permittivity measured by the capacitance sensor used in oil-continuous mixtures (oil/gas/water). The expression of this module is the capital letter "T".
An illustration of the measurement principle is shown below in figure 1.

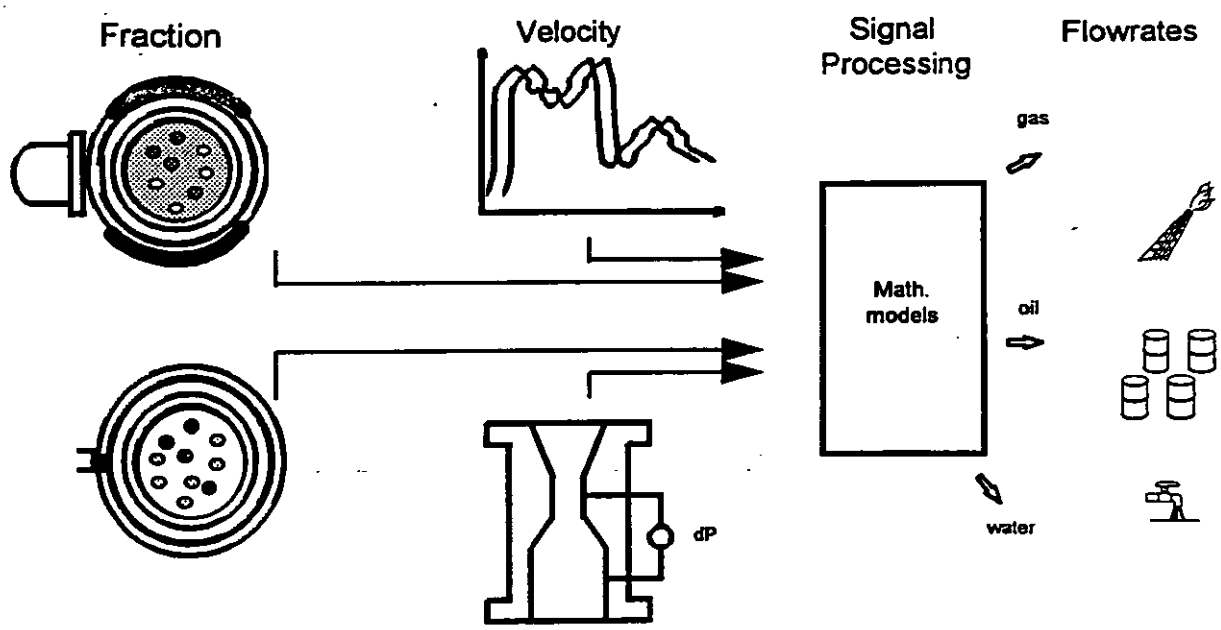


Figure 1 Measurement principle

2.1.1 MPFM 900 series

Flowrates in this meter are measured by a venturimeter "V", and measurements are combined with the fractions. For oil-continuous mixtures (oil/gas/water). The meter is named MPFM 900V. If the meter is to be used for applications in which water-continuous mixtures are expected, it will be delivered with the inductive unit as well, then named the MPFM 900VI.

2.1.2 MPFM 1900 series

This meter uses cross-correlation techniques to determine the velocity of large and small gas bubbles. Simplified, the two velocities indicate the gas and liquid velocity. The sensor contains a number of electrodes with different sizes and patterns, and the two velocities are determined by cross-correlating signals obtained from pairs of electrodes.

The flow velocity can also be determined by the venturimeter. This gives redundancy in the multiphase flow meter. The meter is named MPFM 1900V. If, as for the MPFM 900 series the meter is to be used in water-continuous mixtures the inductive module will be included, and the meter is designated the MPFM 1900VI.

A more detailed description of the operating principles can be found in reference /1/ and /2/. The Fluenta MPFM 1900VI is illustrated in the figure below.

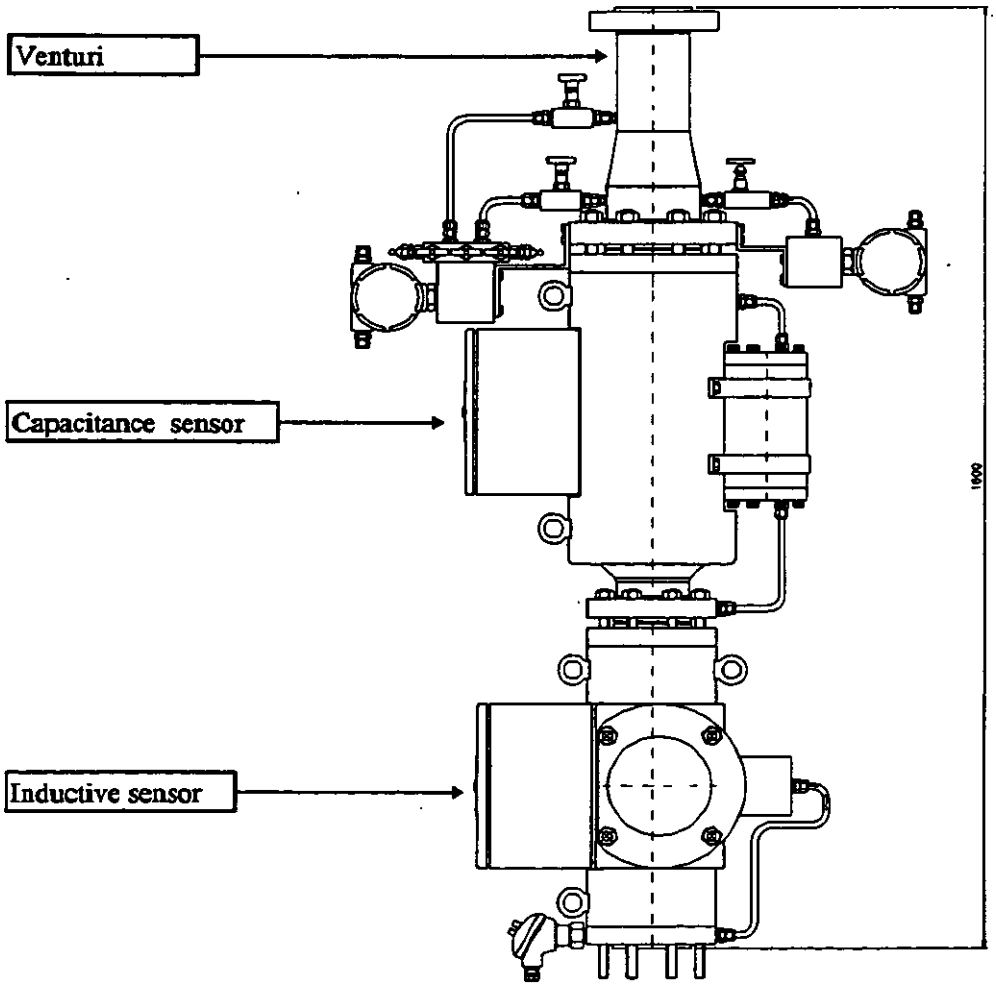


Figure 2 Fluenta MPFM 1900VI

Fluenta has designed a range of meters, underlining our ability to supply our clients with the right meter for specific applications, with respect to price, accuracy, operating range and reliability. Different line sizes are available as well as high-pressure units (15,000 psi). The instruments are designed for use in remote areas where solar panels and batteries may be the only power source.

2.2 Testing and qualification

As the nature of multiphase flow is so complex, it is impossible to generate fully representative laboratory conditions for testing of multiphase meters. For this reason it is essential to develop meters on the basis of experience of a wide range of test conditions and field trials.

This has been the philosophy behind Fluenta's development and so far we have made 15 field installations at many locations in Norway, France, Egypt, UK, and USA. We feel that multiphase meters still have great potential for achieving better accuracy and reliability. Thus we are constantly working on improvements together with companies such as Amerada Hess/Conoco/Saga Petroleum and KFL.

Below we have listed some of the most important tests/qualifications carried out.

Year	Type of test	Instrument	Site - Company
1990	Field test	MPFM 900	Wytch Farm (BP)
1992	Lab test	MPFM 900	NEL Glasgow (Amerada Hess)
1992	Field test	MPFM 1900	Gullfaks B (Statoil/Saga)
1993	Field test	MPFM 900VI	Lafayette (Conoco)
1993	Field test	MPFM 1900VI	Lafayette (Conoco)
1993	Field test	MPFM 1900	Pecorade (Elf)
1993	Lab test	MPFM 1900	NEL Glasgow (Amerada Hess)
1994	Field test	MPFM 900VI	Humble (Texaco)
1995	Lab test	MPFM 1900VI	Hydro Porsgrunn (Statoil/Saga/Hydro)

2.3 Measurement envelope

Very early in the development phase of the MPFM 1900 system, it was found extremely difficult, not to say impossible, to use a mixer to generate a homogeneous mixture over more than a very narrow band of flow conditions. The idea of including some kind of flow conditioner as part of the multiphase meter was dropped, and it was decided to develop a meter capable of a very wide range of operating conditions, requiring no flow conditioning.

In order to limit the range of different flow regimes through the meter, the installation of the meter has been restricted to be vertical with upwards flow, at a distance of 5 - 20 diameters downstream of a blinded T. This installation is shown in Figure 3.

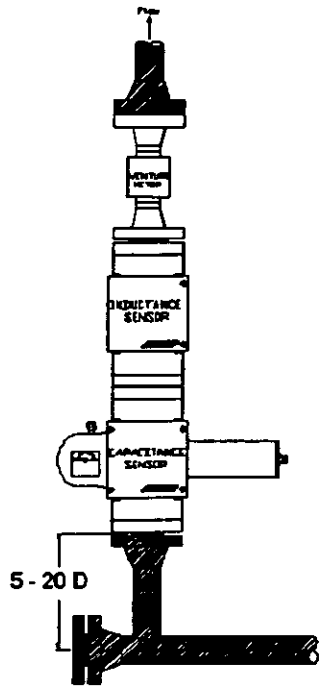


Figure 3 Recommended installation of Fluenta multiphase meters

It is advantageous for a multiphase meter to be able to cover as wide an operating range as possible, for several reasons:

- At the project stage when the design of a multiphase meter must be fixed, there is normally some uncertainty in the process data, and the flow conditions cannot always be confirmed.

- Estimates of flow regimes are very uncertain, particularly for a location where fully developed regimes are not likely to occur.

- The meter may have to operate on a number of wells with very different flow conditions.

- As large a turndown ratio as possible is preferred.

The flow regimes which can occur in vertical upwards flow are illustrated in Figure 4. The meter is capable of operation in all the flow conditions; single phase, bubbly flow, churn flow, slug flow and annular flow. The multiphase meter is relatively unaffected by slug flow, in comparison with process equipment like test separators. Due to the extream high time response of the meter (less than one second) long slugs will not create a problem, since these will be treated as rapid and steady changes in the composition of the flow.

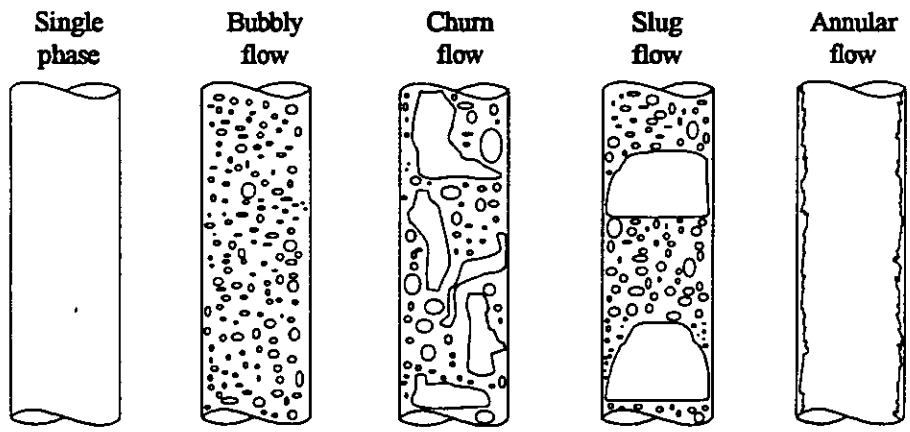


Figure 4 Flow regimes in vertical upward flow

The MPFM 1900 VI has a measurement range of 0 - 100% watercut and 0 - 100% gas fractions.

The multiphase meter has a turndown ratio of at least 1 to 10. For low gas fractions, the minimum multiphase velocity is 1.5 m/sec. For high gas fractions the minimum velocity is 2.5 m/sec. Upper velocity is less critical. For design purposes 1.5 m/sec and. 2.5 m/sec should be used, depending on gas content. As upper limit is less critical, velocities above 15 m/sec through the meter are acceptable. The velocity range is indicated in Figure 5.

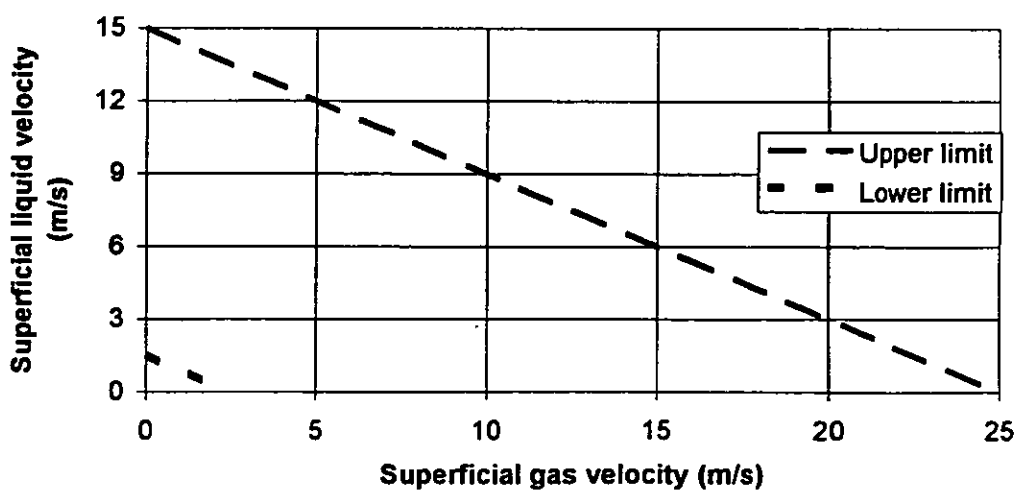


Figure 5 Velocity range of the MPFM 1900VI

2.4 Measurement uncertainties of the MPFM 1900VI

Different flow regimes and changes in the composition of oil, water and gas make it impossible to give one fixed value for the measurement uncertainty. For this reason we have given realistic values of the performance for different ranges of gas fractions. Values are given for liquid flow rate, gas flow rate, watercut and gas fraction. At the outer limits of the operating range, uncertainties might be slightly greater.

On the basis of the results of ongoing qualification tests, new performance specifications for the meter have been defined. Due to requests from potential users the flow rate uncertainties are specified as values relative to actual volumetric flow rates. Uncertainties in fractions are expressed as absolute deviations.

Uncertainties in volumetric flow rates are given as relative uncertainty to actual volumetric flow rates. (not to *total* flow rate)

Fraction measurements are given as absolute deviations from actual measurements.

Total flow rate: ± 5 %

Gas fractions:	0 - 30 %	30 - 60 %	60 - 80 %	80 - 90%	90 - 96%	96- 100%
Liquid flow rate	± 5 %	± 7 %	±10 %	±15 %	±20 %	-
Gas flow rate	-	± 10 %	± 15 %	± 10 %	± 10 %	± 10 %
Water cut (Oil cont. liquid)	± 2 %	± 3 %	± 5 %	± 7 %	± 12 %	-
Watercut (Water cont. liq)	± 5 %	± 7 %	± 10 %	± 15 %	-	-
Gas/liquid fraction	± 2 %	± 2%	± 2%	± 2%	± 2%	± 2%

3.0 SUBSEA MULTIPHASE FLOW METER

3.1 Subsea design by KFL/Fluenta

The project to develop a subsea multiphase flowmeter, SMFM 1000 started in 1994 as a cooperative project between Fluenta and KFL, with Amerada Hess and KFL funding the project. Ref /3/.

Figure 6 Fluenta SMFM 1000 delivered for South Scott

3.1.1 Design criteria

The design of the SMFM 1000 has been based as far as possible on the existing MPFM 1900VI and integrating it with the Kværner FSSL ASE 4000 subsea control system, see figure 7.

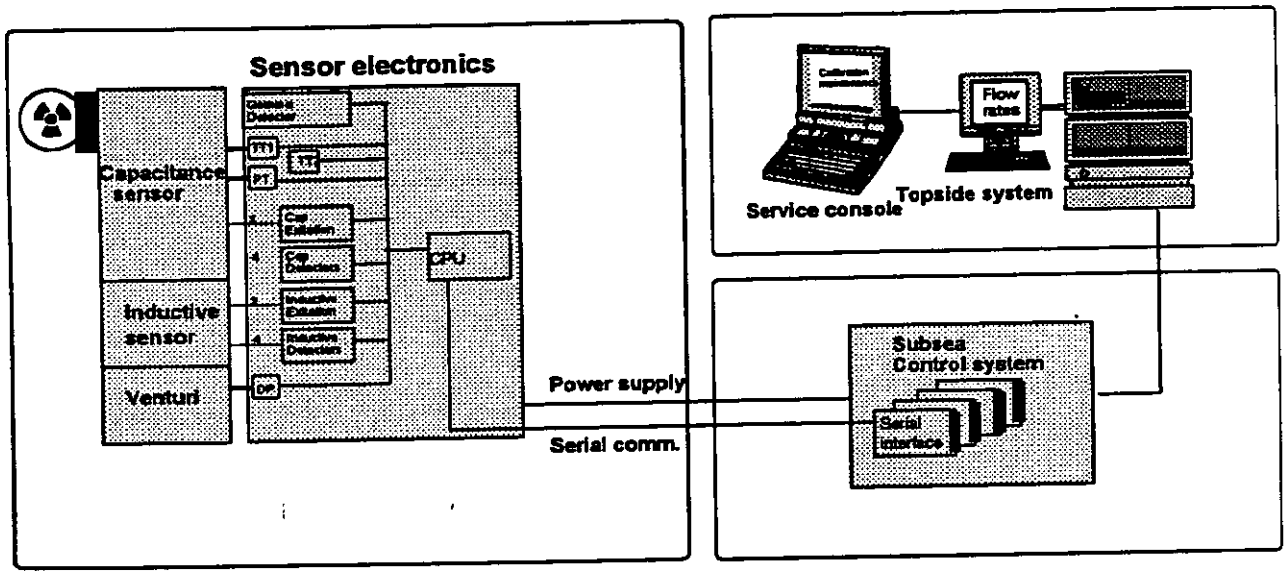


Figure 7 Schematic block diagram of the SMFM 1000

The meter system has been designed in accordance with the following specifications:

Pressure	Up to 6000 psi shut-in well pressure
Temperature	Up to 150°C fluid temperature
Oil Fraction	0 to 100%
Gas Fraction	0 to 100%
Water Fraction	0 to 100%
Sour service	Suitable for fluids with H_2S content up to 600ppm
Carbon dioxide	Suitable for fluids with CO_2 content up to 12 mole%
Min. flow velocity:	1.5 m/sec.
Design life:	25 years in subsea environment

Environmental

Water Depth	670 metres maximum seawater. (All components are easily upgradeable for 2000 m water depth)
Ambient Temp.	-5 to +30°C

MTBF

The system has been designed to have an overall MTBF as high as practically possible, with a design aim of 15 years.

Installation/Replacement

The standard version requires diver-intervention. Alternative designs for ROV maintenance and retrieval of electronics unit or guidewire line installation and retrieval of the complete assembly are available

Materials

Process fluid-wetted parts are made of super duplex stainless steel. Seawater-wetted parts are made of AISI 316 stainless steel, or carbon steel, protected by a paint system designed for long-term subsea use.

Serial Link

Communications between the Subsea Production Control System and the meter take place via a serial link through a cable that also supplies the power. The communication protocol between the meter and the Subsea Production Control System is Modbus.

Power Supply

The multiphase meter's power requirements are 24 V DC, 1.0 A.

3.1.2 Subsea Production Control system

The meter is integrated with KFL's Subsea Production Control System (KFL ASE 4000) which also controls the local manifold, and valves, and acquires data from other sensors. Data from the SMFM 1000 are integrated with the Subsea Production Control System and are available from the platform Data Control System.

The meter could easily be interfaced with similar control systems.

3.2 Qualification of the SMFM 1000 at the National Engineering Laboratory (NEL)

3.2.1 Description of NEL test facility

The Multiphase National Standard Facility at NEL is based on a three-phase separator. This vessel contains the working inventory of oil and water in separate compartments. Each liquid phase is drawn from its separator compartment by a variable speed pump and passed, via the primary reference flowmeter skids, to the mixing section. The gas phase is passed from the supply to the mixing section via a reference meter skid. At the mixing section the water and oil are commingled and the gas phase is injected a short distance downstream. The multiphase mixture then enters the test section, which can be up to 60m in horizontal length or 10m in height. A diagram of the facility is shown in Figure 8. For this evaluation the SMFM 1000 was connected to the facility test section 50m downstream of the mixing section. After the test section the mixture is returned to the separator, where the gas phase is exhausted to the atmosphere and the water and oil are separated by gravity.

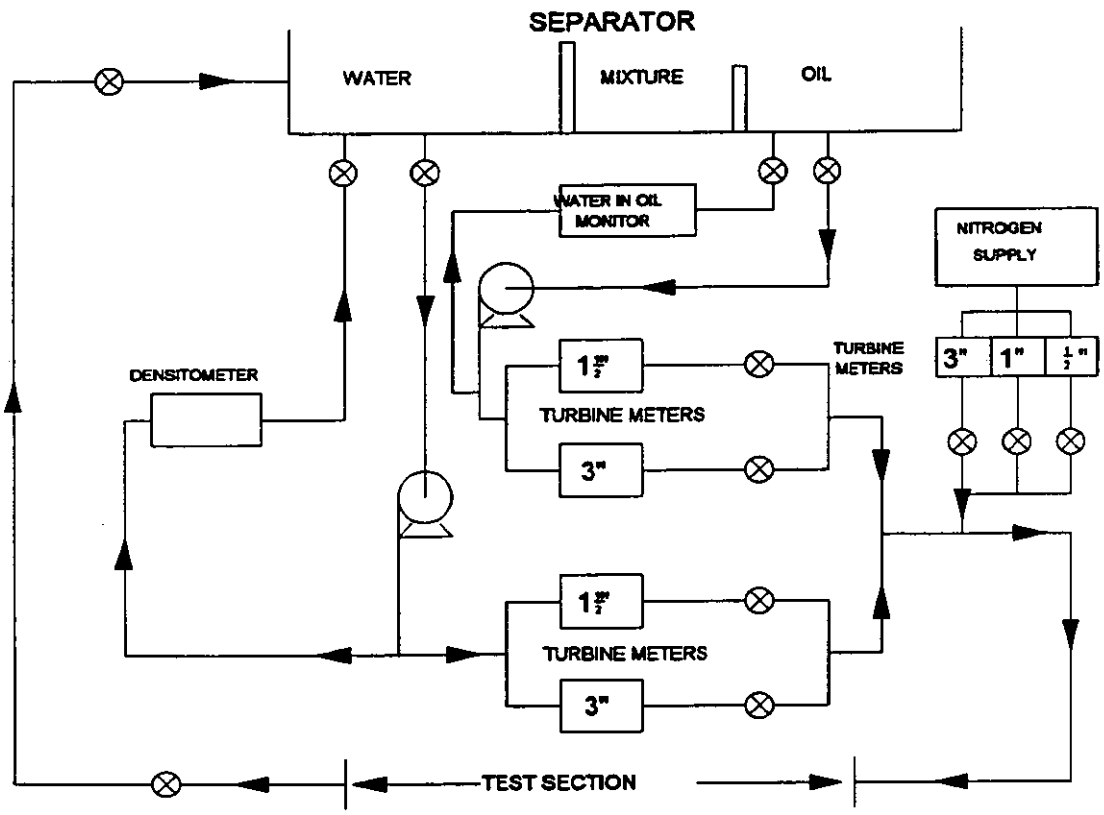


Figure 8 Diagram of NEL Multiphase National Standard Facility

Some carry-over from the separator is inevitable, and both the oil and water feeds from the separator were fast-loop sampled to measure the composition of each process stream. Conditioning circuits allow operation of the facility at temperatures between 10°C and 50°C, to within 1°C, and the operating pressure may be up to 10 bar gauge. Temperature and pressure were also measured at several points in the test section, at the oil/water monitors and at the reference meters and mixing sections.

A programmable logic controller (PLC) controls operation and data acquisition from all the field instruments. During the evaluation all relevant data were written to a test log file which was time- and date- stamped for cross-reference to the SMFM 1000 log file. All measurements are automatically corrected for temperature and pressure, the reference flow rates are also compensated for the carry-over in the process streams. All the instruments are regularly calibrated to local secondary standards, and density curves for the liquid phases are measured before each evaluation commences.

The oil used during this evaluation was a mixture of stabilised Forties crude (flashpoint 60°C) and Exxsol D80 in a 70/30 ratio. The viscosity of the oil was 12.6 cSt at 18°C, and its density was 860.7 kg/m^3 at 20°C. Brine was simulated by the additional of magnesium sulphate ($MgSO_4$) salt to de-ionised water at concentrations of 25g/l and 50g/l. The conductivities of these solutions at 25°C were 0.64 S/m and 1.05 S/m respectively, while the densities at 20°C was 1010.45 and 1018.4 kg/m^3 respectively. The gas phase was nitrogen.

3.2.2 Test matrix and procedure

The basic test matrix is shown in Table 1 and was run for water cuts of 10, 30 and 70%.

Table 1: Evaluation matrix

Qliq (l/s)	GVF 0%	20%	50%	80%
11.1	x	x	x	x
16.67	x	x	x	x
25	x	x	x	
34.72	x	x	x	

For each evaluation the initial condition was set for approximately 20 min in order to enable the SMFM 1000 to achieve thermal equilibrium with the test fluids. After this period the test conditions were set for five minutes to allow the conditions to stabilise, before data recording started. The reference flow rate measurements were recorded at five-second intervals for one minute, and the SMFM 1000 readings were continuously averaged and written to file every minute. The PC system clocks were synchronised prior to each evaluation in order to permit cross-reference and comparison of the readings.

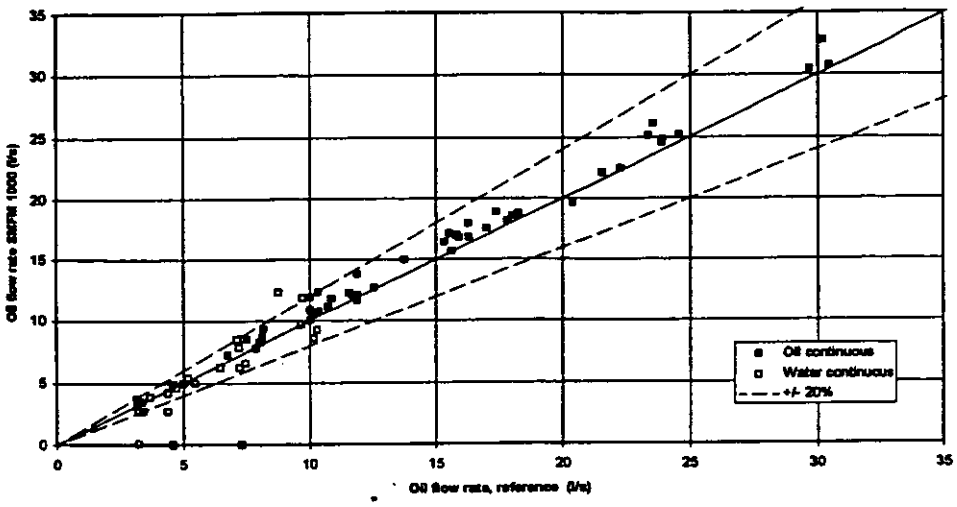
An additional repeatability test was performed continuously over an eight-hour period. The condition was set to 16 l/s and 50% Gas Void Fraction (GVF) and the water cut was cycled at 30 minute intervals between 30 and 70%. The SMFM 1000 data were recorded continuously during the test, the reference data were stored at one-minute intervals over a twenty-minute period at each stabilised condition.

3.2.3 Test results

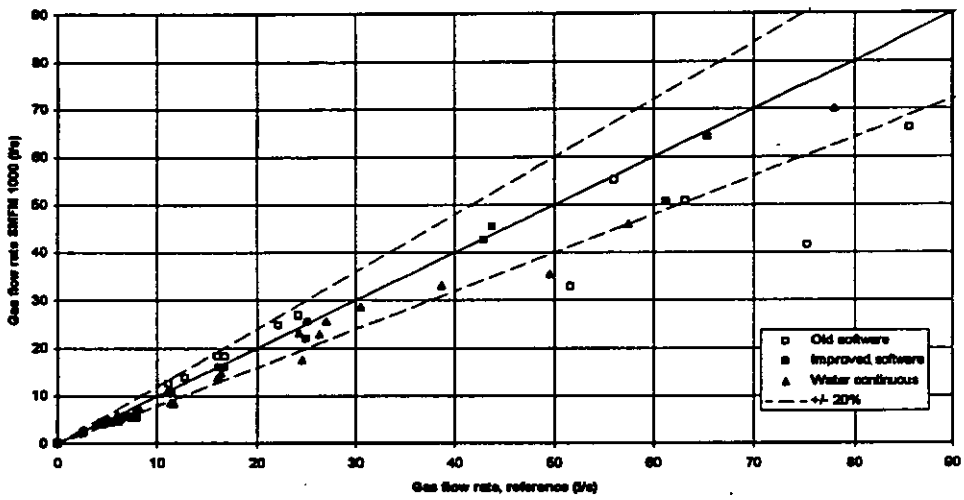
The SMFM 1000 tested at NEL measured the individual flow rates by means of a multi-velocity system based on cross-correlation of capacitance signals, with a venturi meter providing additional velocity measurements. Fractions of oil, gas and water were determined by combining capacitance and gamma densitometer signals in the oil-continuous phase, and by combining inductance and gamma densitometer signals in the water-continuous phase. This eliminates the need for any mixing device, since the meter is capable of measuring both gas and liquid velocities (slip conditions).

Figure 9, shows separate graphs for oil flowrates, gas flowrates and water flowrates for all test points run during the extensive test series. Oil- and water-continuous test points have been plotted together, but with different legends. During the test, new improved software was installed. Test points from these tests have been given their own legend.
All test points have been plotted against the reference values from the test-rig. A deviation band of ± 20% has been dotted into all graphs.

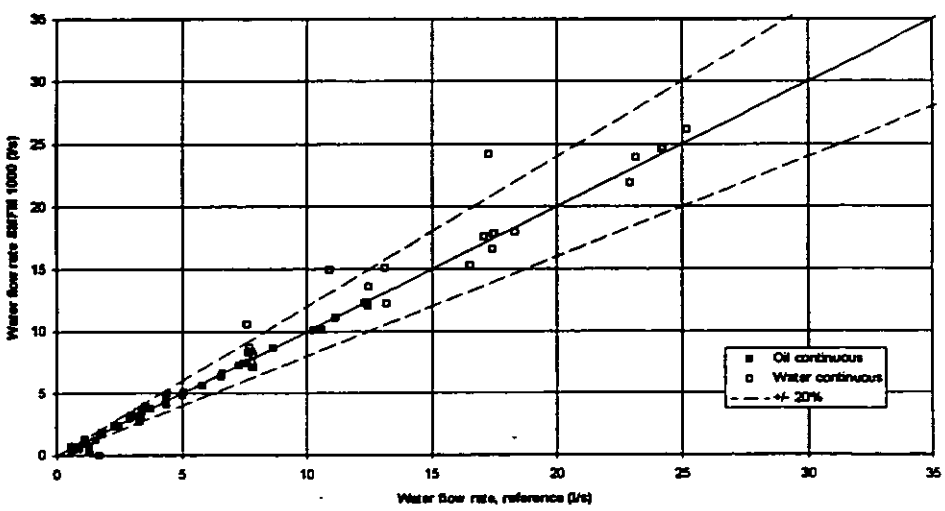
In figure 10, the test results have been plotted against the claimed specifications given by Fluenta for oil- and water-continuous flow. In the watercut versus gas fraction graph, both claimed specifications for oil- and water-continuous flow have been plotted, since these are not the same. The dotted lines represent specifications for water continuous flow, while the continuous lines represent oil-continuous flow. Virtually all test points were inside the limits specified, although the gas flowrate was generally underestimated. Most of these underestimated test points occurred when the GVF was lower then 20% (then only the venturi was used for velocity measurements), when flowrates were low and at the lower limits of the dP transmitter's operating range in the venturi.
At high GVF there was a great improvement with the new software. These test points have been given their own legend.



Oil flow rates



Gas flow rates



Water flow rates

Figure 9

NSFMW 24-26 Oct. '95
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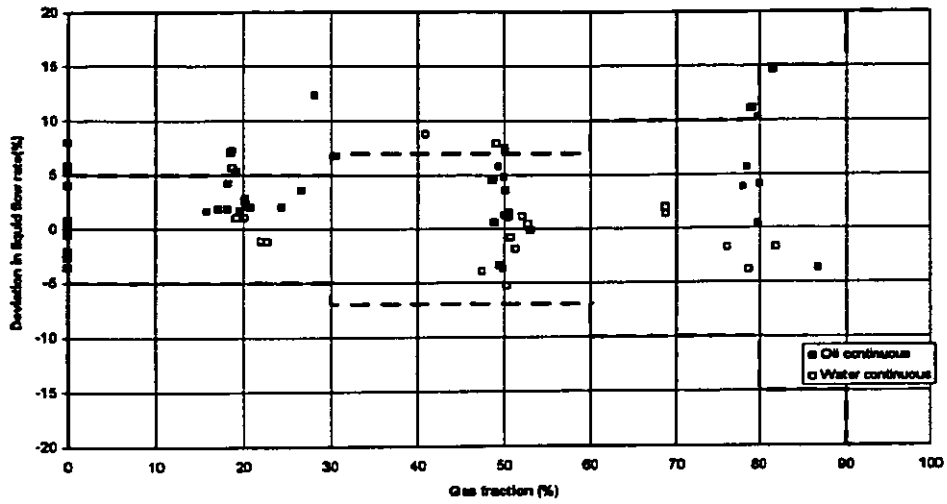
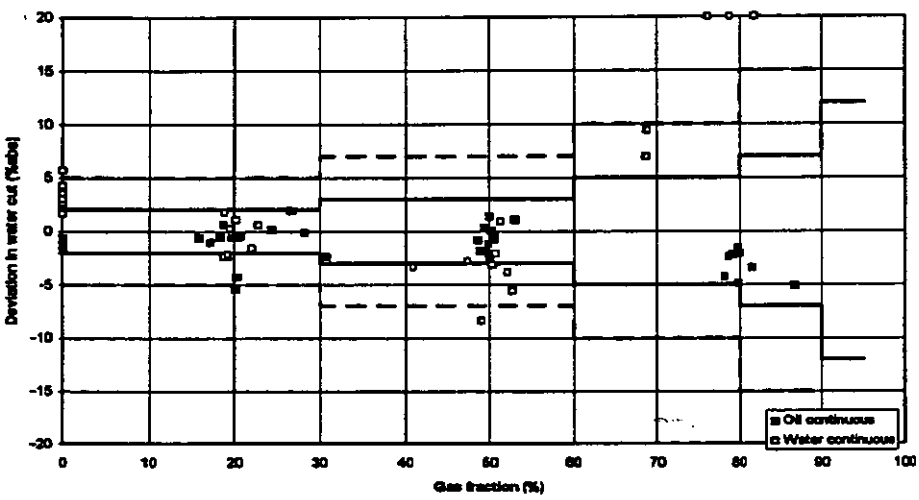
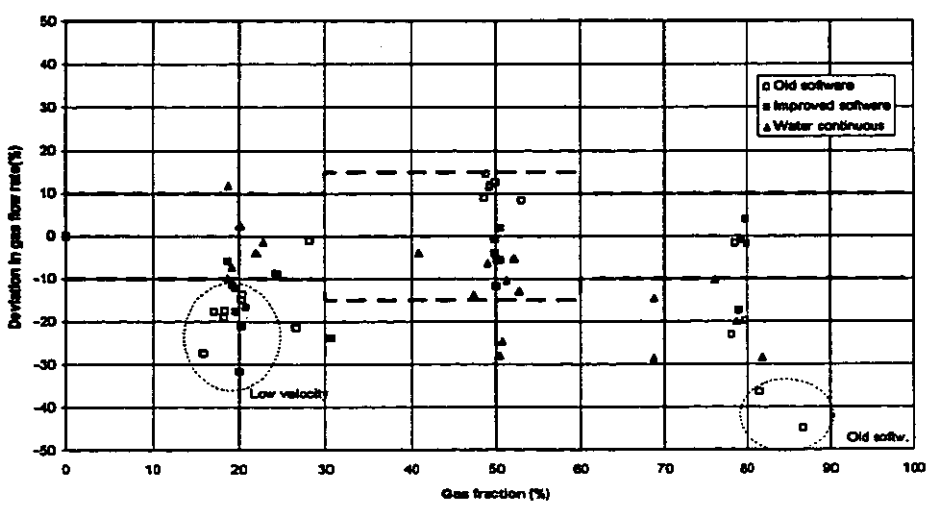


Liquid flow rates vs. gas fraction



Watercut vs. gas fraction



Gas flow rate vs. gas fraction

Figure 10

3.2.4 Conclusions

The meter performed reliably during the evaluation once it had been set up. No intervention was required. The measurements of phase flow rates reflected the changes made to the reference flow rapidly and followed the trends closely. Operation was not affected by whether the liquid mixture was oil- or water-continuous. In general the meter performed optimally in making velocity measurement using the venturi meter, or the venturi combined with the cross-correlation meter.

The gas flowrate was consistently under-estimated across the range of GVF tested, and the magnitude of the error increased with GVF. During the limited range of tests in which the new software was used, gas flowrate measurements were much improved, particularly at high GVF.
This trial demonstrated that there may be scope for improvement in the software model; this could have a beneficial impact on the meter's performance, particularly at high GVF.
The repeatability of all measurements was seen to be very good when cycling from oil- to water-continuous regimes.

On the basis of these excellent results, Amerada Hess found the meter acceptable for installation subsea at the South Scott field.

3.3 Fluenta SMFM 1000 installed in the South Scott template

South Scott is an extension of the main Scott reservoir and contains recoverable oil reserves of approximately 60 million barrels. The South Scott manifold is located 5 km south of the Scott platform. The field has been developed with a manifold for four wells and a production line tied into the Scott platform. No test line has been installed. Savings obtained by Amerada Hess in using this SMFM 1000 instead of a traditional test line solution are expected to be around GBP 8 -9 million. Ref. /4/.

The SMFM 1000 has now been installed on the seabed as part of the South Scott manifold and after recent successful commissioning and checks of communication and static readings we are currently waiting for "first oil" which is due before the end of September.

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Main Index

North Sea FLOW Measurement Workshop 1995

Paper 21:

WELLCOMP MULTIPHASE FLOW METER -Oxy field experience with replacement of traditional well test separators

4.5

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WELLCOMP MULTIPHASE FLOW METER

Oxy field experience with replacement of traditional well test separators

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SUMMARY

Over the past five years, Occidental has been working on proving technology for separation and metering of multiphase wellhead fluids to replace conventional well test systems. The technology selected has over the past two and one half years been in operation in the Occidental operated Block 15 of the Ecuador Oriente.

Occidental has faced and addressed several challenges, however, the technology is proven to the operator of Block 15 as justifiable on the original grounds of having environmental, economic, operational, and technical merit over conventional test separation. This new technology well test equipment holds great promise for meeting the needs of timely and accurate well test data, which are so essential for maximizing oilfield recovery and ensuring sound reservoir management.

This paper details Occidental's experience with the WellComp well test system from lab to full field replacement of traditional test separator systems. These experiences reveal not only the benefits but the "real world" problems associated with introducing new technology into the field. Although the paper presents the basic operation and specific experiences related to the WellComp system, many benefits and solutions may be helpful in application to any new well test technology introduced into a production operation.

ECUADOR BLOCK 15

In February 1985 OEPC signed a risk service contract for Ecuador Block 15. The next seven years saw the discovery and subsequent proving up of commercial oil reserves, leading to the approval of the Block 15 Development Plan in July 1992 by PetroEcuador.

Block 15 is in an area of intense international environmental scrutiny. As shown on *Figure* 1, the Occidental block contacts three national ecological preserves of international profile, with a fourth Area added in 1994. Within this operating sphere, the Occidental development plan was approved as a model of environmentally responsible oil development in recognition of the rich ecological heritage present in the Upper Amazon Basin of Ecuador.

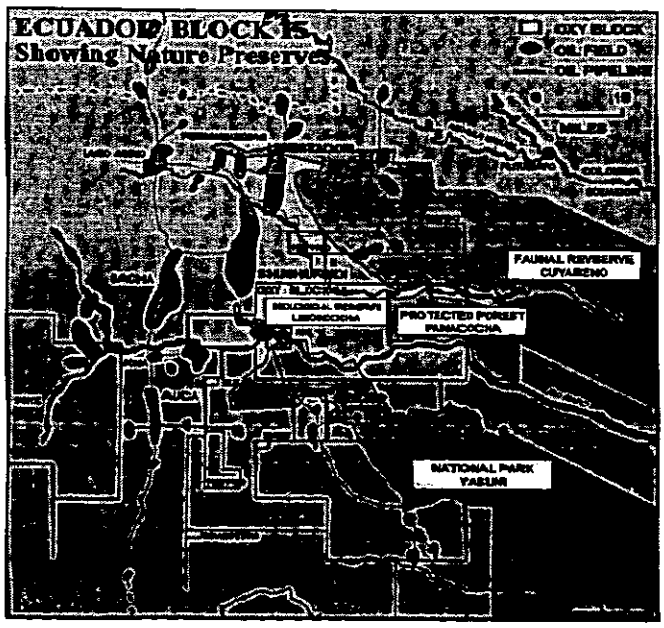

Figure 1

The current development of the Jivino-Laguna and Napo fields is shown in *Figure* 2. Presently the fields are developed with twenty producing wells and two water injection wells. Four to ten directional producing wells are drilled off each well island. Individual well testing is done through test manifolds at each well island. A multiphase gathering pipeline carries the commingled production to the Central Production Facility (CPF). Separation of the bulk fluids takes place at the CPF, where:

- oil is processed to pipeline conditions and pumped to the PetroEcuador pipeline at Shushufindi for onward transmittal into the trans-Andean pipeline;
- water is separated and processed to an acceptable standard for injection in the subsurface;
- gas is dehydrated and used for fuel with the excess flared.

The development consists of the following key components, to minimize the impact of sub-surface oil development on the Amazon rain forest:

- directional well drilling from four principal well islands;
- burying well flowlines and trunklines;
- injection of produced water in compatible sub-surface reservoirs;
- well testing at flowline conditions from sub surface multiphase pumping without benefit of further surface pressure boosting to the single separation facilities.

Proven technology was available to Occidental in 1990, to accomplish all of the above components except the last. Occidental set about at that time to gain experience with and prove up technology that could be recommended to PetroEcuador as part of an ecological balanced oil development for Block 15; the later component was critical not only in environmental terms but for costs and proper technical management of the encountered oil reservoirs.

Figure 2

SELECTION AND TESTING OF THE WELLCOMP

The initial design criteria of the wellhead testing of Block 15 wells was to:

- test well effluents produced by subsurface Electrical Submersible Pump (ESP) at Well head Pressure (WHP) of 2.8 mPa (400 psig) and 93 ° C (200 ° F);
- have flow ranges between 160 and 1,270 m^3/day (1,000 and 8,000 bfpd) and water cuts varying between 5 and 95 %;
- have gas produced in GOR ranges of 18 to 62 Sm^3/Sm^3 (100 to 350 scf/stb);
- have accuracy of measurement to be within 10 % on oil/gas/water rates;
- have recombination after analysis to bulk line and be pumped using subsurface ESP to central gathering and separation point.

After a review starting in late 1990 of the then available technology, the FloComp II unit (predecessorto the WellComp) was identified and was judged to be the most developed technology in meeting these five requirements. Accordingly, a single FloComp II was purchased in June 1991 for testing and evaluation within the fields operated by Occidental in the USA, with similar crude characteristics to those found in Ecuador. It was predicted, that should the technology be proven in Ecuador it would have future economic benefit through use in many similar Occidental developments, including multi-platform offshore developments.

In November 1991, the unit was tested in the Kern Front field of Bakersfield, California. Twenty tests were conducted on 19 different wells. The purpose of this testing was to monitor at low rates the separation and metering characteristics on low gravity crudes. Well fluid rates ranged from 5 to 127 m^3/day (30 to 800 bfpd) and water cuts varying from 62 to 95 %. The results were deemed successful with an average absolute deviation of:

- oil rate against tank metered volumes of 10 % and,
- water cut against conventional grind out measurements of 5 %.

Based on these tests, Occidental proceeded to file a development plan for Block 15 built with the WellComp as the pivotal technology. This plan was approved by PetroEcuador in August 1992.

One of the main advantages of the WellComp equipment was the reliance on predominately proven technologies. The use of coriolis meters and vortex shedding meters on well testing equipment was an established applied technology within Occidental operated fields, and the static analysis chamber technology, although unproven, was easily tested in a lab, independent of actual flowing conditions in the field.

The proposed Ecuador development would produce from three separate reservoirs with:

- oil gravities of 0.95 from 0.89 S.G. (18 and 28 degrees API);
- water salinities varying from 400 to 43,000 ppm Cl^-;
- gas gravities varying between 0.84 and 1.29 S. G. , due to varying oil PVT properties and CO_2 spatial variations within the productive zone.

Since the relative proportion of these gravities within a given well would be unknown, the sensitivity of the analysis chamber results to these inlet fluid stream density variations was a source of concern. Prior to placing the order for the units, further operational testing in the laboratory was deemed necessary on the analysis chamber of the WellComp equipment.

Tests were set up in the laboratory of WellComp in Orange, California to test the unit accuracy with emulsified fluids and various mixtures of heavy/light crudes with varying amounts of fresh/salt water and air. These results showed agreement within 10 % of the theoretical fluid volumes, and encouraged Occidental to proceed with another field trial prior to ordering for Ecuador. The 10% deviation appeared to be predominately a result of variations in internal coating of the chamber with the heavy crude. These results spawned a new analysis chamber development by Paul Munroe, that would eliminate these coating variation effects.

WELLCOMP DESCRIPTION

In November 1992, the WellComp was shipped to the Occidental Johnson-Grayberg lease near Midland, Texas for final testing. These tests were to confirm previous testing in accuracy of measured oil, water and gas and to test the operation of an upstream fluid conditioner under higher gas production rates. These tests required the simultaneous flow of up to six wells in order to approximate the rates of the Ecuador wells. Overall, these tests were a overriding success and confidence builder for Occidental, they indicated an average error as compared to the proven well test facilities on: oil/water cut of +/- 1.6 % and total fluid of +/- 1.8 %. Gas measurement was out of range for the Occidental test facilities, therefore this portion of the test was not achieved.

Figure 3 shows a pictorial of the basic equipment contained within a WellComp. A quick overview of the basic operation follows:

Incoming three-phase flow enters the fluid conditioner where slugs and large bubbles of free gas are removed from the liquid stream. Essentially, the fluid conditioner is similar to a two- phase separator system, with the exception that well-entrained gas is allowed to flow with the liquid out the bottom of the unit (a "1-1/2 phase" separator is far smaller than traditional 2-phase separator system). This liquid/ entrained gas mixture is metered volumetrically through a volumetric meter, and ultimately recombined with the free gas stream at the exit of the unit. Free gas is metered from the top of the fluid conditioner through a vortex shedding meter. A differential pressure gas regulator and a liquid throttling valve maintain separator fluid level, ensuring operation through severe slugging and allowing accurate operation from 100% gas through 100% liquid flow regimes.

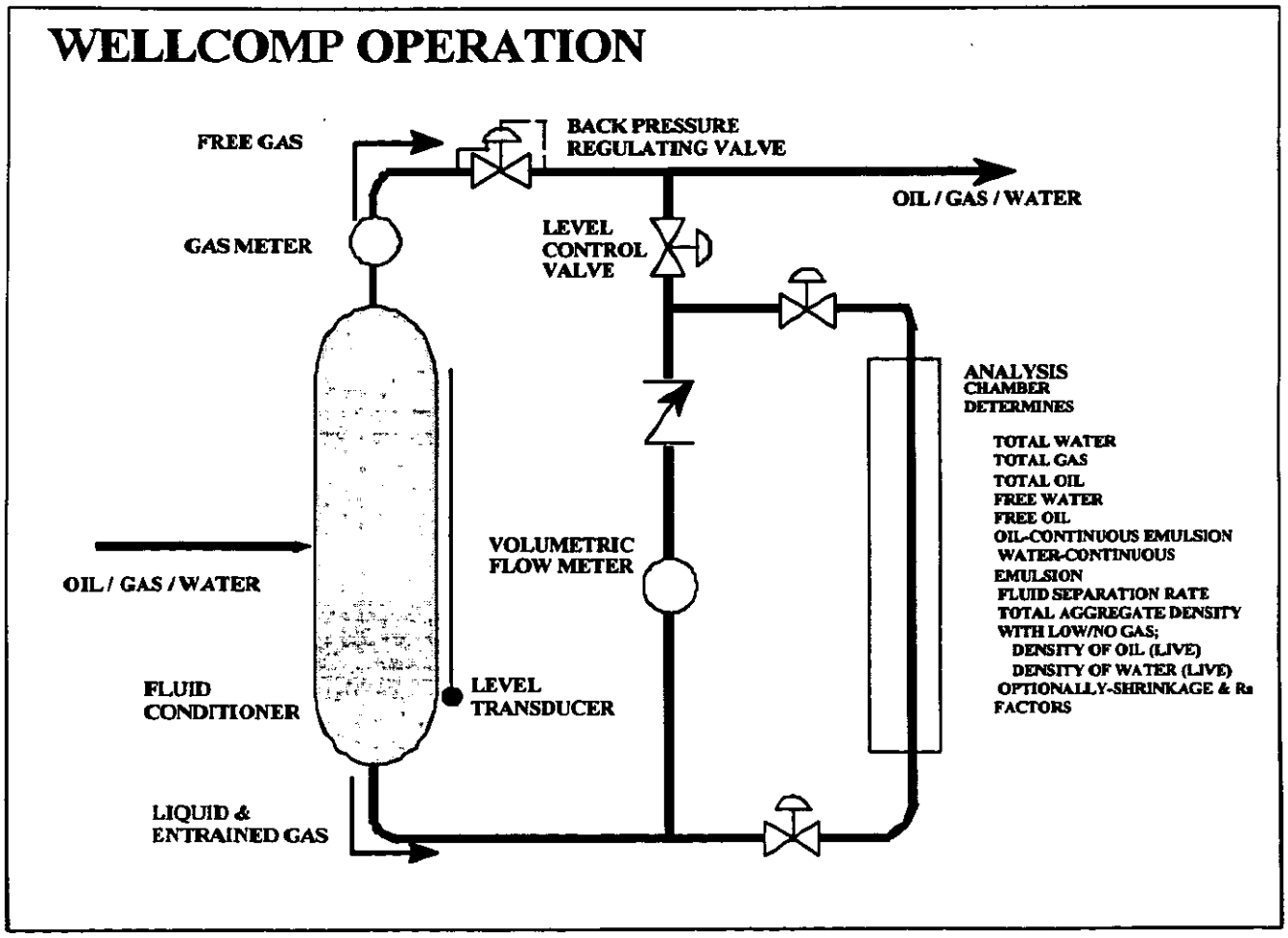

Figure 3

Every five minutes, the 3-phase primarily liquid flow from the bottom of the fluid conditioner is diverted from the volumetric metering device through a section of pipe named the analysis chamber. Valves top and bottom are shut to trap a sample in this two meter vertical section of pipe. A volumetric analysis is performed on this static sample over a four minute period for oil, water, and gas content. The established volumetric fractions of oil, water, and gas are multiplied by the total volumetric rate to produce the flow rates of each component. Pressure and temperature transducers are used to correct each component to standard conditions, and gas rates are added to standardized free gas rates measured from the gas leg. These results from the five minute "Mini-Test" are stored in a local data acquisition system, and a new test commences. This cycle repeats for a predetermined period, set by the operator, at which time all mini-test results are averaged for a "Final-Test" record to be displayed and stored in the database.

The analysis chamber uses a differential pressure transducer to establish the aggregate density of the static sample. This measurement predominately determines the gas vs. liquid (water & oil) content in the chamber. A proprietary probe will make 150-300 separate capacitance readings vertically over the two meter length of the analysis chamber. The result is a profile as shown in *Figure* 4. This measurement predominately measures the water vs. hydrocarbon (oil & gas) content in the chamber. A solution to three equations in three unknowns is used to permit analysis of fluids from a fully emulsified to a fully stratified state. The analysis also determines the percentage of fluids that remain emulsified at the completion of the five minute equilibration period. *Figure* 5 shows a local LCD panel that displays well test results both graphically and in tabular format, allows calibration of equipment and entry of an automated sequence of well tests (integral command of automated test manifold valves).

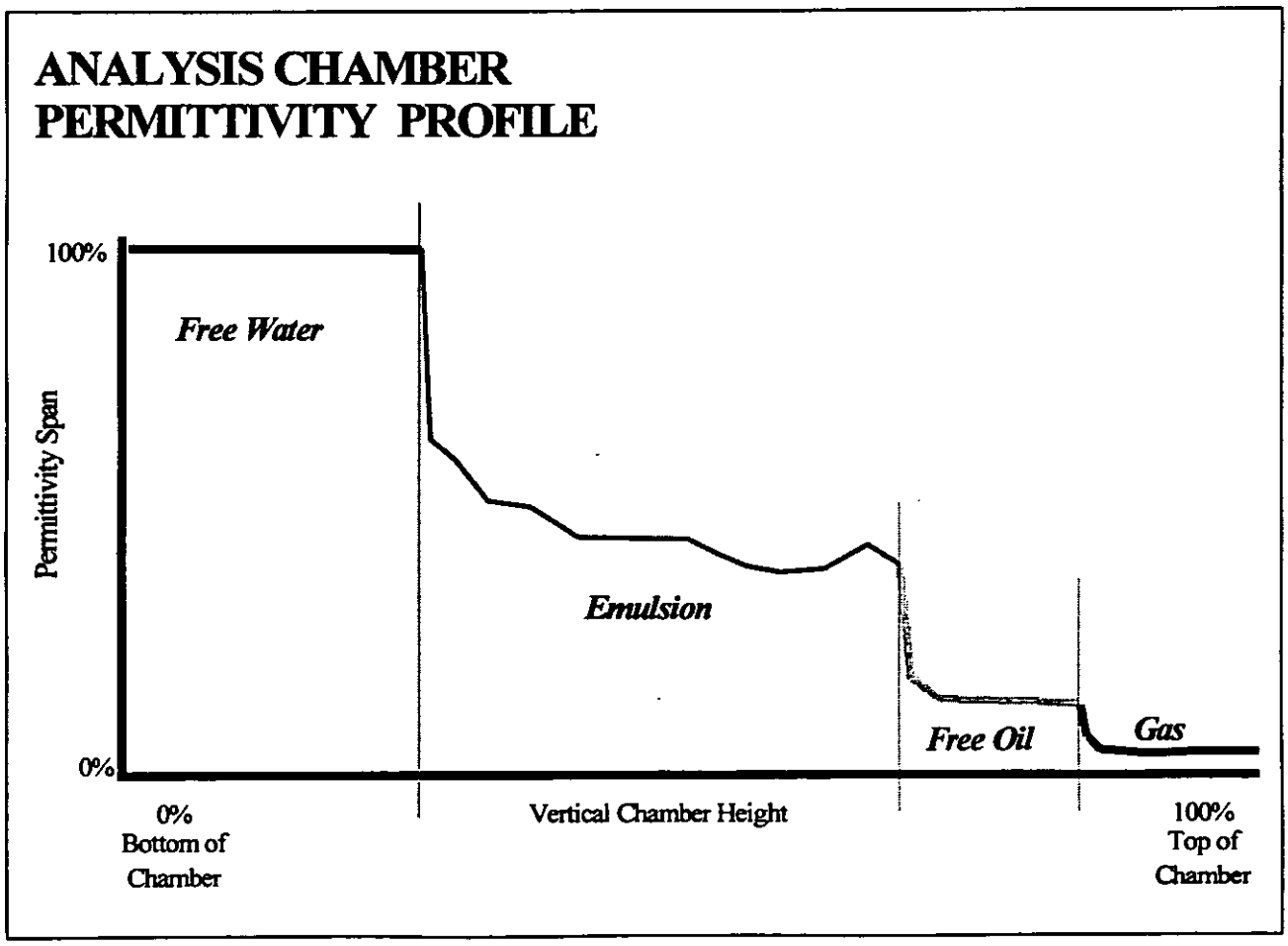

Figure 4

BLOCK 15 INSTALLATIONS

In December 1992, five additional standard model 400 WellComp units with high gas fluid conditioner were purchased for use in Ecuador. The first two of the units arrived in Ecuador in April 1993. On May 1, 1993 production started through early oil facilities situated on the Jivino A platform. This unit performed from inception giving daily accurate well test data under Amazon jungle ambient conditions with only a tarp for cover from the rain. Subsequent installations during the early oil phase were completed on the Laguna A and Jivino C platforms. In August 1993 the CPF was commissioned and an additional installation was made on the Jivino B platform. Finally, with the discovery of the Napo field in early in 1995, the unit already in place on the Laguna A platform was accepted by PetroEcuador for accurate segregated testing of the Napo field produced fluids. A typical well island hook up is shown on *Figure* 6.

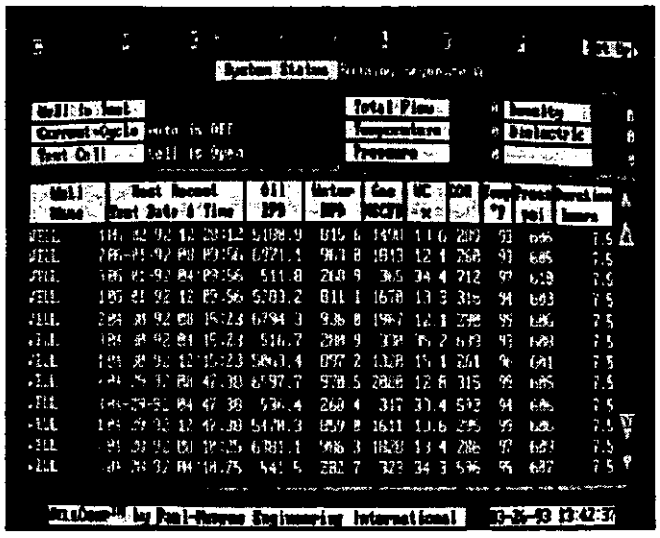

Figure 5

In the early portion of the application of this technology in well tests on initially completed wells and for the entire production stream from May to August of 1993, the WellComp measurement was compared against conventional test separation metering equipment. After confidence was gained in the application of this technology, use of other test methods have not been necessary.

Current Operation and Allocation of Produced Fluids

Oil, gas, and water production from individual wells are measured in each well island (Jivino-A, Jivino-B, Jivino-C and Laguna-A) on a daily basis, through the WellComp units. Wells are producing at an average wellhead pressure of 1.7 mPa (250 psig) and 93 ° C (200 °F).

Producing wells are usually tested for a period of two hours, with a minitest performed every five minutes (as detailed above). The production test figures, for oil, gas and water for a particular well, is an average of the 24 minitest performed in the two hours period.

Production data from Block 15 is collected and controlled per well daily. Once the production for the Block has been determined, a Block correction factor (or lease factor) is calculated to guarantee that the total sum of oil, and gas and water production per well is equal to the total production of theBlock. The lease factors for oil, gas and water are used to adjust the net oil production for each one of the producing wells, giving the allocated production of oil, gas and water.

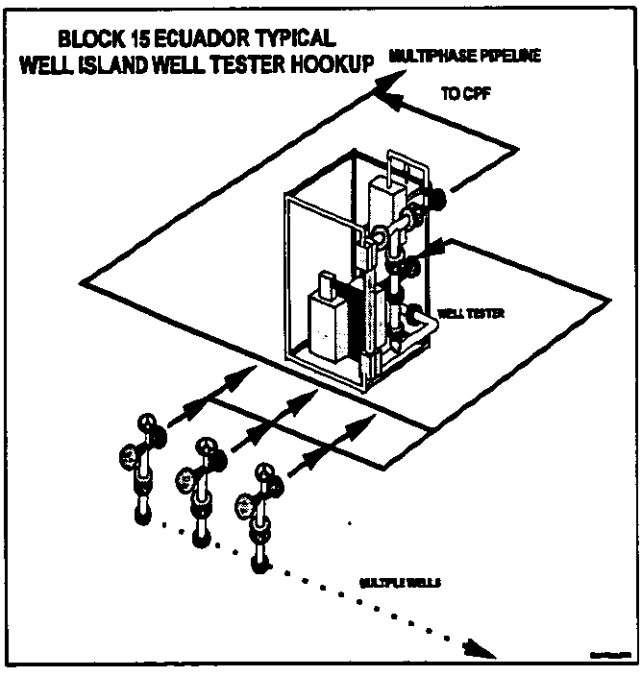

Figure 6

The daily oil lease factor and the number of wells in operation are shown in *Figure* 7 from March 1994 to July 1995. The daily oil lease factor is defined as the:

> Cumulated individual well tests at standard conditions for a 24 hour period using the last accepted test for the individual well, compensated for the down time if any that the well experienced during the period, divided by the stanadard condition oil measured by the fiscalization meter for the same 24 hour period compensated for any stock level changes.

In the graph the WellComp averaged test readings corrected for well down time and stock level changes are compared against the block oil fiscalization meter.[1] Data quality have improved and special events are shown annotated on the curve, during a period of increased system complexity with the number of wells quadrupling over the period shown.
Of special note is the period preceding July 1994 (note 1). Paul Munroe technicians, combined with a trained OXY expert made adjustments to the four WellComp units and corrected several hardware problems. Lease factors in subsequent months improved greatly. A second significant upward trend in the lease factor began in January 1995, which forced re-examination of the units (note 2). It was discovered that various individuals with access to the WellComp configuration menus had different interpretations of some key calibration parameters. Additional training in the proper calibration setup of the units, combined with tight control over changes made to the calibration resulted in a sharp improvement in lease factor.

It must be kept in mind that this data is not a laboratory comparison of WellComp data against a single standard measurement. Significant errors can come into this data which are not dependent on the WellComp, for example errors in: wells on or off, stock level changes, temperature and pressure corrections to crude oil, wells cleaning up, and frequency of testing. This measurement is primarily dependent on the WellComp data and as such is the primary field data quality standard used by Occidental for the test measurement.

Data from individual well islands is taken by floppy diskette to the CPF for integration into the well allocation software. The "Production Operator's Workstation and Reporting" (POWAR) computer system is currently used for collecting data in the field and then moving it through the CPF oil accounting system. Reporting requirements are handled automatically within the program: test information, downtime, stock volumes and balancing, proration factors, etc..

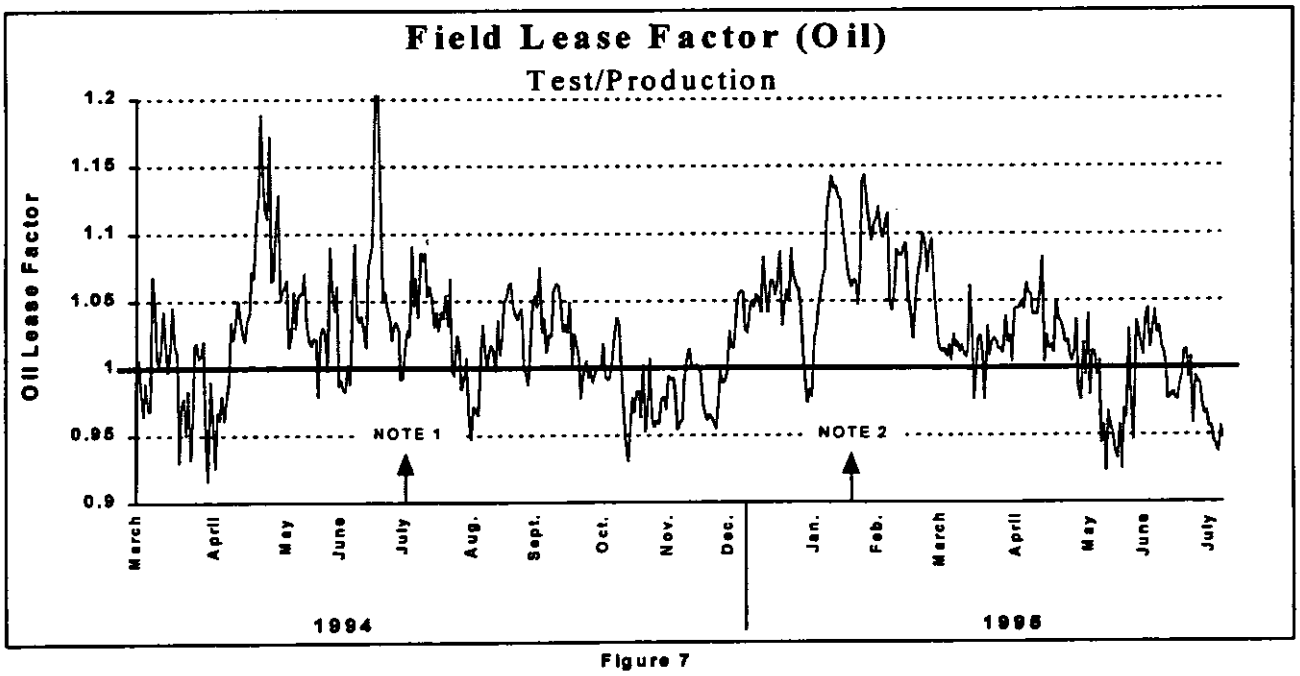

Figure 7

An interface to POWAR was developed for production allocation at reservoir level for wells with commingled production, and for generation of special production reports formats required by the Company and by the Government.

Operating Parameters and Flowrate Ranges

At the initial start-up of the first WellComp unit at Jivino A in May 1993, apparent discrepancies to the LACT production figures were detected because WellComp was displaying the production figures at the line operating conditions and the LACT figures were given at standard conditions. The WellComp unit was then calibrated to display the data at the same standard conditions as the LACT unit.

To optimize the accuracy of the four WellComp Units installed in Jivino-Laguna-Napo field, the following data for each well on the four production well islands was predetermined and programmed into the Units: (1) density of oil, water, and gas at operating conditions; (2) shrinkage factor for oil that corrects the oil measured at operating conditions to standard condition, taking into consideration the effects of dissolved gases, temperature and pressure; and (3) dissolved gas factor (R_s) that indicates the volume of gases coming out of solution as the oil drops to ambient conditions. Update and adjustment of this data improves overall accuracy in wells producing from multizone completions, where the possibility of widely varying oil and water densities exist.

The following table shows the overall range of well flowrates measured by the 4" WellComp in Block 15 and the range of fluid characteristics handled.

OPERATIONAL CHALLENGES

During the two and one half years the WellComps have been in operation in Block 15 numerous challenges have been met and overcome. These are important parameters to keep in mind wherever technology of this type is considered for application.

Strong Working Relationship between Vendor and Operator

Based on this experience, the successful application of oilfield technology requires the close coordination between the technology developer (Paul Munroe Engineering) and the technology user (Occidental). Most of the successful efforts during the program resulted from close coordination; In contrast, most of the setbacks in the program were a

	RANGES OF FLOW RATES			FLUID CHARACTERISTICS		
	Oil m^3/d (bopd)	Water m^3/d (bwpd)	GAS- Sm^3/day (mcfpd)	Oil Grav. S.G (API)	Water salinity ppm Cl^{-1}	GAS GRAV. Air = 1
Minimum	24 (150)	0	28 (1)	0.95 (17.1)	400	0.84
Maximum	1,200 (7,500)	1,200 (7,400)	11,000 (400)	0.89 (27.0)	43,000	1.29

[1] The fiscalization meter is a: Daniel Industries 6 inch dual case positive displacement meter, with a flowrate design of 30,000 bopd under conditions of 0.91 s.g. oil at 88 °C, with proving by means of: Daniel Industries Bi-Directional mechanical displacement meter prover.

result of poor coordination and lack of goal alignment between Paul Munroe Engineering and Occidental personnel. It is important that early goal alignment be pursued between the developer and the user of oilfield technology of this type.

Strong Management Commitment

Field personnel familiar with traditional test separators were initially skeptical regarding the accuracy and functionality of the WellComp equipment. A strong commitment by management to utilize this equipment and to maximize the use of the abundant information produced by the unit was essential to overcome this initial resistance. Attitudes from the beginning of the program changed dramatically once technical personnel took ownership of the equipment and began maintaining it themselves. Now there is unanimous consent among field personnel that this equipment is a superior replacement for traditional test separators. In general, any new-technology equipment placed into the oilfield typically requires strong sponsorship by management to ensure the overall success of the program.

Technical Support and Training

Twice in the last two and one half years the lease allocation factors have forced a major look at both the hardware and software of the units to confirm the best possible data is being obtained from the units for proper management of the Block 15 reservoirs. The first evaluation resulted in some major operational revelations:

In the case of traditional three-phase separators, it is essential to have knowledgeable personnel operate and maintain the equipment, and to collect, correct, analyze, and assemble well test results. They must use their experience and judgement about the historical data from a given tested well, in order to provide accurate well test data and diagnose production equipment problems. Although the WellComp promised to eliminate many of the "expert" personnel requirements and reduce the human subjectivity of final test results, initial underestimation of the type of support required for operation and maintenance of the equipment became an obstacle for the success of the program.

Since the overall technology was new, and the latest developments were to be included by the time equipment was to be delivered, a great deal of dependence was placed on the manufacturer for operation and maintenance of the equipment over the first year. Inexperienced technicians from Paul-Munroe and the lack of an OXY technical expert trained in the operation of the WellComp unit amplified the initial teething problems. Upon realization of these shortcomings, Paul-Munroe responded with higher qualified technicians and OXY committed to a training program for OXY field technicians to take over operation and maintenance of the equipment. The strategy was successful, and the equipment has been operated and maintained by OXY personnel for the past one and a halfyears with minimal support from Paul-Munroe.

The second evaluation of the equipment due to lease factor allocation factor analysis revealed inconsistencies in those calibration parameters which directly affect the final test results. Additional training with regard to requirements for the key calibration parameters, and tighter control over changes made to these parameters has resulted in reliable well test data from all sites.

Automation Valves

The initial Block 15 manifold and WellComp order envisioned, that wells be routinely automatically cycled into test with well status and test flags (on/off) signal to the CPF Process Logic Controller (PLC). This portion of the project was cancelled after partial automation of three wells. This has resulted in a continued need for permanent production staff at each production island to turn wells into test and locally monitor equipment on an hourly basis. This has reduced the economic benefits of the system to the operator. It is recognized, that this is not ideal since a partially automated system results in minimal economic benefit compared to a fully automated system.

CONCLUSIONS

The following general conclusions have been reached with respect to the five years of experience Occidental and Paul Munroe have with testing and field proving of wellhead testing technology.

1. Lab and field trials prior to full field utilization are important to addressing early the critical technology issues prior to application; and led to a successfully field application.
2. The cost of technical support for operation of the units in a remote international location were underestimated by Occidental at the time the unit was selected. In spite of this overall unit cost increase (considering the additional cost of technical support for fifteen months) the WellComp units have maintained a cost advantage over traditional well site testing in Block 15.
3. Irrespective of personnel costs associated with the maintenance of the WellComps, the maintenance material costs have averaged to date less than the value of one barrel of oil equivalent per unit day of operation.
4. Some additional technical support on hardware and software is required on an on-going basis, but this is not inordinate and the Occidental staff maintenance of the units is going well and in line with the maintenance of other oil field application technology in use by Occidental.
5. The WellComp unit has proven to be key to meeting the environmental goals for the project to allow multiphase flow to a central producing station, with no compromise on well test data for effective reservoir management in Block 15.
6. Test accuracy obtained from the unit exceed conventional test separation capabilities and indeed initial Occidental objectives over a wide range of flow conditions.
7. The automation benefits of the system have been reduced by the lack of actuators on the test manifold valves tied back to the central station. Were this to be carried through it is anticipated that further economic automation benefits would be realized from the WellComp units in Block 15.

FURTHER TECHNICAL ADVANCEMENTS - POST BLOCK 15

Several technical advances have been made over the past two and one half years since installation of the original WellComp units. New computer hardware and software on the unit provides connectivity to multiple devices. The unit may be controlled, and data downloaded via an infrared palmtop or notebook PC, and may simultaneously communicate with a local PC operator station, a remote SCADA system (MODBUS slave RTU), and a local RTU for valve automation. Curves for shrinkage and R_s may be entered (instead of single point entries), and calibration of most instruments have been automated. Additionally, extended on-line diagnostic capabilities report failures and miscalibration on many instruments.

Fluid conditioner designs have advanced, and level control now includes adaptive gain algorithms to provide robust operation over a wide range of flow conditions, without the need for operator interaction.

Developments continue to fully utilize the computer ability to set-up, calibrate, diagnose, and report data on the WellComp unit. Work also continues to reduce the size of the fluid conditioner and keep the overall footprint to a minimum.

One of the challenges facing Occidental is how to use the large volume of reliable data now available from the WellComp, and to integrate and link that data to other Block 15 production system components. The data available from the WellComp and linkage to other system components is the next step in advancing the use of the technology. Other system components to which the WellComp is currently not linked, include the Variable Speed Drive (VSD) for the downhole ESPs and the automation and control system at the CPF.

This linkage is important so the entire production process can be improved. At present the different system components are reviewed functionally rather than in a process manner. A true process look will require integration of data an understanding as a process rather than a series of functions relating to one another, e.g. Maintenance and Production.

Closing Remarks

Our objective as an industry in multiphase flow measurement is and should remain:

"Have available to the oil and gas producer and in-line wellhead device, which can provide and integrate to a daily basis, accurate three phase (gas, oil, water) flowrates and fractions independent of transient fractional variations in volume or gravity of the three phases."

The technology has not arrived to accomplish this lofty and worthwhile objective. The WellComp however, is a significant intermediate step on this particular path of technical evolution.

Main Index

North Sea FLOW Measurement Workshop 1995

Paper 23:

OIL COMPANIES NEEDS IN MULTIPHASE FLOW METERING

4.6

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Oil companies' needs in multiphase flow metering

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ABSTRACT

In the last year BP, Statoil, Saga, Norsk Hydro and Shell have established a multiphase metering forum. The objectives of this is to identify common needs and interests for possible co-operation between the oil companies. The aim of this paper is to broadcast key areas of need so far identified by this forum.

The participants in the forum have reviewed a number of potential multiphase metering applications for each oil company. The review clearly showed that there is a widespread need for systems that provide adequate oil, water and gas measurements at gas volume fractions (GVF) between 50% and 99% and that can handle high volumetric throughputs (exceeding 60,000 m^3/day in some cases). The determination of water cut in a range from zero to above 90% is also needed in many applications.

The reservoir and petroleum engineering needs were also addressed, yielding some general ranges for a multiphase meter's accuracy: 5% to 10% error (relative to the individual phases) for both the total liquid flow rate and the gas flow rate, and no more than 2% absolute error in water cut. (This paper calls for the specification of accuracy in such terms.) The specific demands for a meter's accuracy, of course, ultimately depend on its envisaged application; they sometimes can be relaxed in favour of the meter's consistency of performance. Finally, the forum underscored the importance of calibrating meters particularly under conditions of varying produced-water salinity.

INTRODUCTION

The availability of multiphase metering systems is seen by the oil companies as a major cost saver in the development of hydrocarbon reservoirs. Many oil companies have been actively pursuing the development of such metering systems, either through Joint Industry Projects or through their own research and by making test facilities available. These efforts, together with the expertise and the perseverance of the equipment suppliers, have led to the appearance of first-generation multiphase metering systems on the market. It is now up to the industry to successfully implement the current generation of meters and to set new development targets so that the technology matures in the coming years.

In the last year, BP, Statoil, Saga, Norsk Hydro and Shell established a multiphase metering forum to identify common needs and to see what opportunities there were for possible co-operation between the oil companies. So far, the participants in the forum have had four meetings. In these, many aspects of the development, performance, testing and implementation of multiphase metering systems were addressed. The participants felt it appropriate to communicate to the industry, by means of this paper, the common needs that they have uncovered. These needs can be grouped into four aspects of multiphase metering: flow ranges; user requirements; performance specification; and calibration methods.

POTENTIAL MULTIPHASE METERING APPLICATIONS

Each of the participating oil companies has analysed their potential multiphase metering applications. Selected applications were reviewed by the forum, and some of their typical characteristics are presented in Figs 1 and 2.

BP Application

This four-well satellite field will be tied back to a processing platform in the North Sea through a 35-km multiphase pipeline. Conventional well-test facilities relying on a test pipeline would be uneconomic and are unworkable within the metering scheme. This example (Figs. 1a and 2a) illustrates the wide range of flow rates with which the metering scheme will operate over the field life, including high gas volume fractions. The design case is for a subsea installation, in water 95 m deep, that handles fluids flowing under natural reservoir pressure. An alternative production scheme is based on water injection, which would result in higher water cuts. The capability to determine water cut over its full range will be required in many BP Exploration applications around the world.

BP's global multiphase metering perspective ranges from low-rate heavy-oil wells (as low as 32 m^3 liquid per day) to high-volume producers (4000 m^3 liquid per day at 75% - 90% GVF). Some gas-condensate applications will require shut-in pressure ratings of up to 1000 bar.

Statoil applications

The prospect consists of two neighbouring fields in the northern part of the North Sea at a water depth of 135 metres. The field development will be based on a subsea production system. The first field has four producers; their commingled flow will be transported 25 km for processing. The production time for the field is estimated to be 15 years. Reservoir pressure will be maintained through gas injection. The second field will produce hydrocarbons from two different reservoirs. The first year's production will come from five wells in one reservoir and three in the other; ultimately there will be a total of 13 producers. The total productive lifetime of the field is estimated to be 16 years. The entire production will be transported to an existing processing facility, some 8 km away. Figures 1b and 2b show the expected production for a typical well in the first reservoir. Multiphase meters will be needed both topside, for measuring the total flow, and on the subsea template, for measuring individual wells.

Shell Expro applications

Field 1:

This is a small gas field in the central North Sea for which four subsea wells are planned. A floating production, storage and offtake (FPSO) unit is being designed for this field, and a multiphase meter is being considered for well testing. The meter is to be installed inside the turret of this FPSO, resulting in savings on the use of swivels, flowlines and deck space. The FPSO will be used for several other fields later on. The multiphase flowmeter must be suitable for the other fields; otherwise, a test separator would need to be retrofitted. The field is due to start up in 1997, and a decision to use a multiphase flowmeter system will have to be taken by the end of 1995.

Field 2:

This field is one of the high-pressure and high-temperature fields in the central North Sea. It is most likely to be developed around a Not Normally Manned satellite installation. The

Figure 1: Two phase flow maps

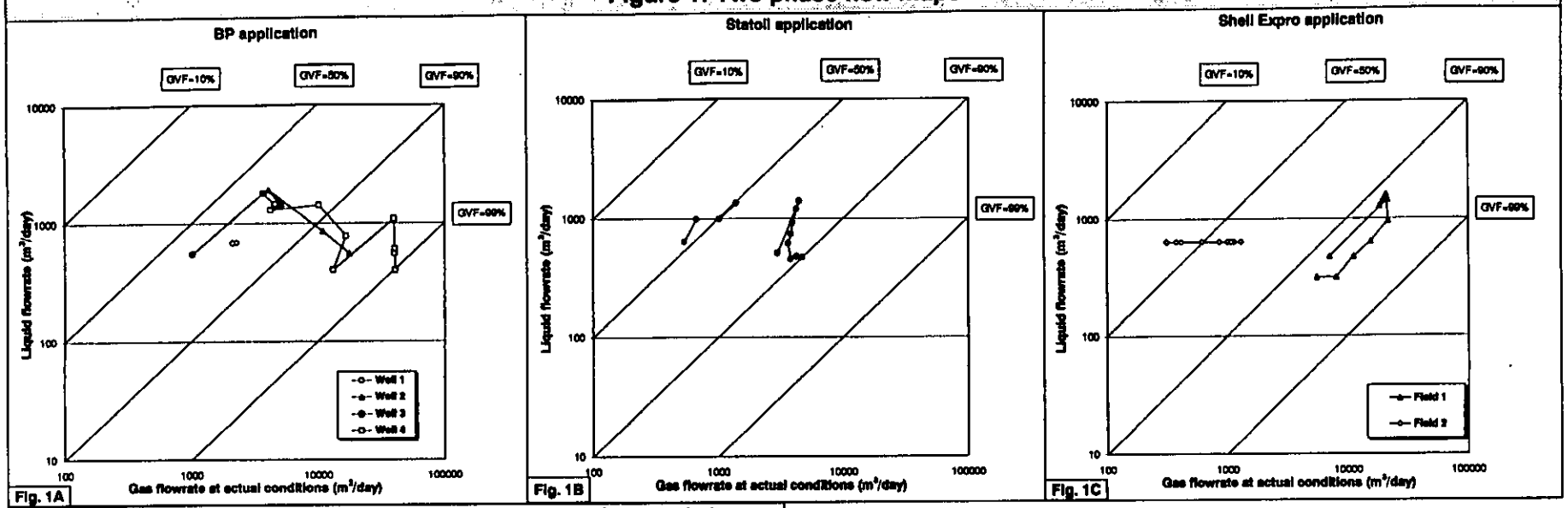

Fig. 1 Collection of two phase flowmaps showing the flowrate ranges of some typical multiphase metering applications. Each point represents a consecutive year.

Figure 2 Multiphase composition maps

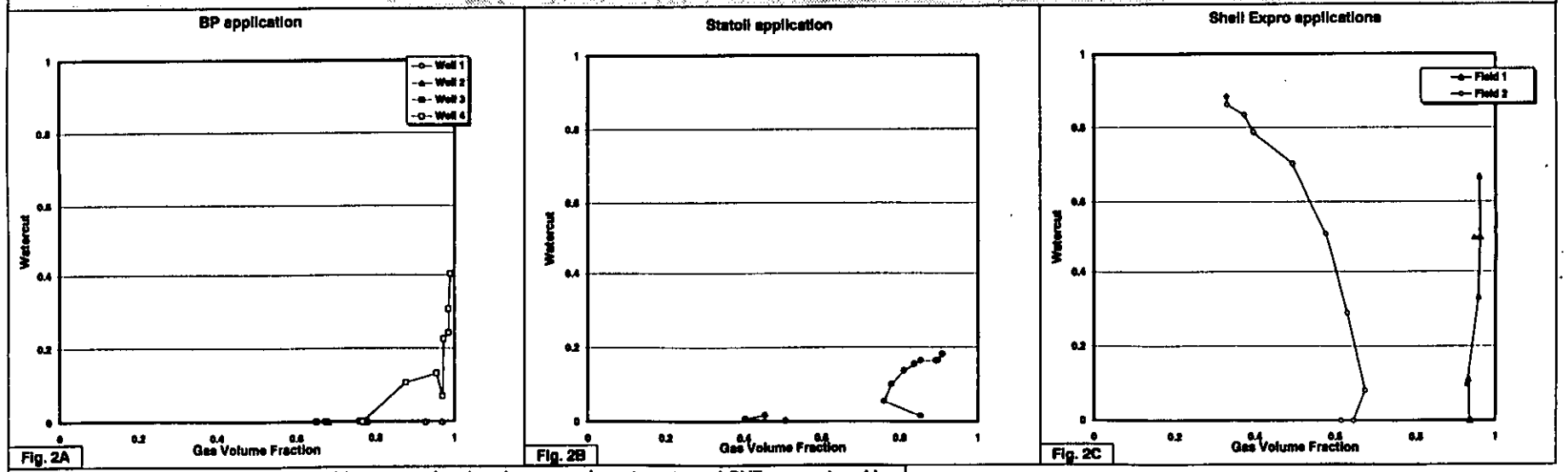

Fig. 2 Collection of multiphase composition maps showing the ranges in watercuts and GVF encountered in some typical multiphase metering applications. Each point represents a consecutive year.

processing will thus take place at central processing facilities nearby. Owing to the chemistry of the field, very heavy scaling is expected. Before it is installed in this field, a multiphase flowmeter will therefore have to be assessed as to its susceptibility to scaling. Also, the high pressure (15,000-pound class) and high temperature will require special meter designs. Field start-up is planned for 1998. The decision to employ a multiphase flowmeter is required before the end of 1995.

Common characteristics of well streams

Having reviewed a number of applications of the forum oil companies, the participants could straightforwardly deduce a number of common characteristics: Large well stream throughputs of up to 5000 m^3 of liquids per day and 60,000 m^3 of gas per day at line conditions are not uncommon. These are likely to require 6- to 12-inch meters. Evidently, for total satellite allocation even higher flow rates have to be metered. High GVF (exceeding 70%) is commonly seen. In many cases wells have a water cut that ranges from 0 to over 90% over their life. Conditions of high pressure and high temperature are also found, particularly in the North Sea area.

RESERVOIR/PETROLEUM ENGINEERING NEEDS

Surveys of the accuracy specifications that would be needed for multiphase flow measurement within the forum oil companies have revealed the following general requirements:

- 5% to 10% relative accuracy in total liquid flow rate;
- 5% to 10% relative accuracy in gas flow rate;
- 2% absolute error in water-cut measurement.

Specific accuracy requirements, of course, will depend on the application. If a multiphase meter is used as a means of allocating production amongst different equity holders using shared processing and export facilities, then the lower limit of ±5% of oil and gas flow rate is more likely to apply—indeed, an even tighter specification might be desirable in some cases.

For reservoir management, on the other hand, the well-test data has several possible uses, and the accuracy and repeatability requirements vary accordingly. Historical well-test data are used for production forecasting and reserves determination. Well workover decisions depend on up-to-date well tests, and—as soon as they are worked over—the wells are usually re-tested. Decisions about expensive development or in-fill drilling programmes are also based on well-test results. The performance of a gas-lift system or an electric submersible pump can be optimised on the basis of well-flow measurements.

Production optimisation similarly relies on well testing to determine the gas/oil ratio (GOR), water cut and oil-rate data for each well so that the well rates may be "tuned" to achieve maximum revenue under given processing-facility constraints. A survey of reservoir-engineering requirements for a range of applications revealed that the desired accuracy in the GOR measurement varied widely, from between 1.5% and 3% in one case to 15% in another. The more stringent tolerance for GOR error is perhaps indicative of a reservoir engineering ideal, given the capabilities of conventional well-test equipment. The looser specification is for a case where well chokes are to be adjusted for maximum oil

production through gas-constrained facilities. (A similar requirement may exist when gas production from a gas cap above an oil rim is to be avoided.) Realising that the GOR is the ratio of average gas flow rate to average oil flow rate from the well, one should nonetheless carefully assess the phase flow rate error specification. In the worst case, the GOR may be derived from gas and oil rates whose errors are additive. Each phase, if equally uncertain, would then have to fall within a 7.5% relative error tolerance band in order to satisfy the overall 15% accuracy in the GOR. Moreover, one should not forget that flow rate quantities and ratios are usually required in standard or stock-tank units. Near-wellhead measurement systems therefore will have to be corrected on the basis of fluid state (PVT) data, which present an additional source of measurement error.

Still, it is not difficult to envisage potential applications where the accuracy requirements of multiphase meters can be relaxed. If, for example, the revenues from particular well streams are relatively low, then obviously the accuracy tolerances could be at the loose end of the ranges given above. In some cases the lesser accuracy of multiphase meters could be offset by the fact that well-stream measurements could be taken much more often than conventional test-separator measurements.

Multiphase meters that have been combined with test separators so as to allow more frequent measurements could also afford to be less accurate, but then they must exhibit a high level of repeatability: they must have a "stable" response. To date, most available data from multiphase-meter tests has been collected in flow loops and field trials covering different flow conditions. Attention now needs to be focused on the furnishing of repeatability or response-stability data, which are acquired from multiple readings under closely reproduced flow conditions.

Just as a relaxation of accuracy requirements does not apply to all fields neither does it apply to all measurements. Oil companies are increasingly operating in fields where wells can economically produce significant reserves even at water cuts above 90%. In such circumstances accurate monitoring of the water cut (given by the ratio of the average water flow rate to the average total liquid flow rate) is critical for making shut-in decisions. Because a measurement error can significantly influence the amount of recovered oil and the length of the field life, an accuracy to within ±2% absolute or better is demanded.

Given the variation in requirements across applications, it is essential that facilities designers, engineering contractors and meter vendors have an open dialogue with reservoir and petroleum engineers, who must establish user needs on the basis of the reservoir depletion strategy. Further, metering system specifications must fully account for flow rate ranges over its service life, including an allowance for reservoir uncertainty. Consultants, contractors and their clients must realise, in turn, the substantial investment of time and effort needed by the vendor to tender a proper multiphase meter quotation. Co-operation will be necessary to allow vendors, intermediaries and end users to properly assess and qualify the multiphase metering system.

PRESENTATION AND SPECIFICATION OF METER PERFORMANCE

The forum discussions have revealed likes—and definite dislikes—regarding the presentation and specification of meter performance. Two-phase flow maps and multiphase composition maps (see Figs. 1 and 2) are preferred for presenting flow-rate ranges and indicating the location of test data. Furthermore, errors in phase flow rate should be

presented as a percentage of phase flow rate. The forum also prefers the presentation of the accuracy in the water-cut determination to be in terms of absolute error. The forum found it unhelpful and even confusing when errors in flow rates were expressed as a percentage of total volume flow rate. The same applies for quoting relative errors as a root-mean-square average over a number of wells or test points. The vendor should in any case be able to demonstrate the performance of his product with traceable test data.

(IN-SITU) CALIBRATION OF METERS

An important aspect of a multiphase flowmeter is its calibration. Once the meter is physically installed, initial calibration and set-up procedures need to be carried out to arrive at the claimed accuracy and repeatability, regardless of whether these have been derived for production-allocation or for reservoir-management purposes. Yet this essential metering support function has received relatively minor attention over the last 10 years or so of metering hardware development. It is unclear, for example, how remote stand-alone multiphase meters will be calibrated in situ. Depending on the application, such calibration will not only be required initially but also at subsequent intervals.

Hence, multiphase metering systems should incorporate means for in-situ checking or calibration, both of compositions and of rates. Facilities designers should be aware of the sub-systems required for such purposes. For example, purge systems or valve arrangements could be used to introduce single-phase fluids of known properties into composition-sensing cells. Procedures might also be drawn up for summing the total mass of fluids from metered wells and comparing that with the measurement of total production. Alternatively, one could consider deploying more than one multiphase meter for cross-checking purposes.

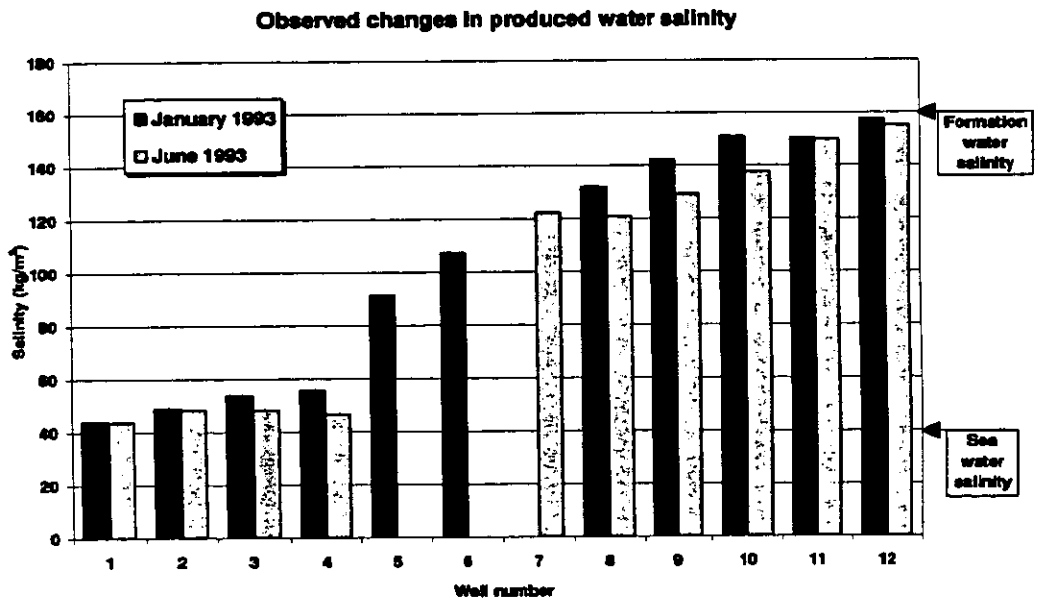

Figure 3 **Produced-water salinities for a North Sea reservoir as measured in January and June 1993.**

Composition-measurement devices must also be capable of compensating for fluid-property variations (e.g. fluid densities). In many potential multiphase-meter applications, for instance, the salinity of the produced water—a key calibration parameter—will not be constant in time. In water-injected reservoirs the salinity will change from the original

formation-water salinity to the injection-water salinity. As an example of this, Fig. 3 shows the produced-water salinities for the wells of a North Sea reservoir as measured in January and June 1993. It is seen that salinity is different for each well in the same reservoir and that in a six-month period the salinity for some wells changed by more than 10 kg/m³. Indeed, horizontal and/or vertical gradients in formation-water salinity amounting to salinity variations much larger than 10 kg/m³ across the reservoir may occur [1].

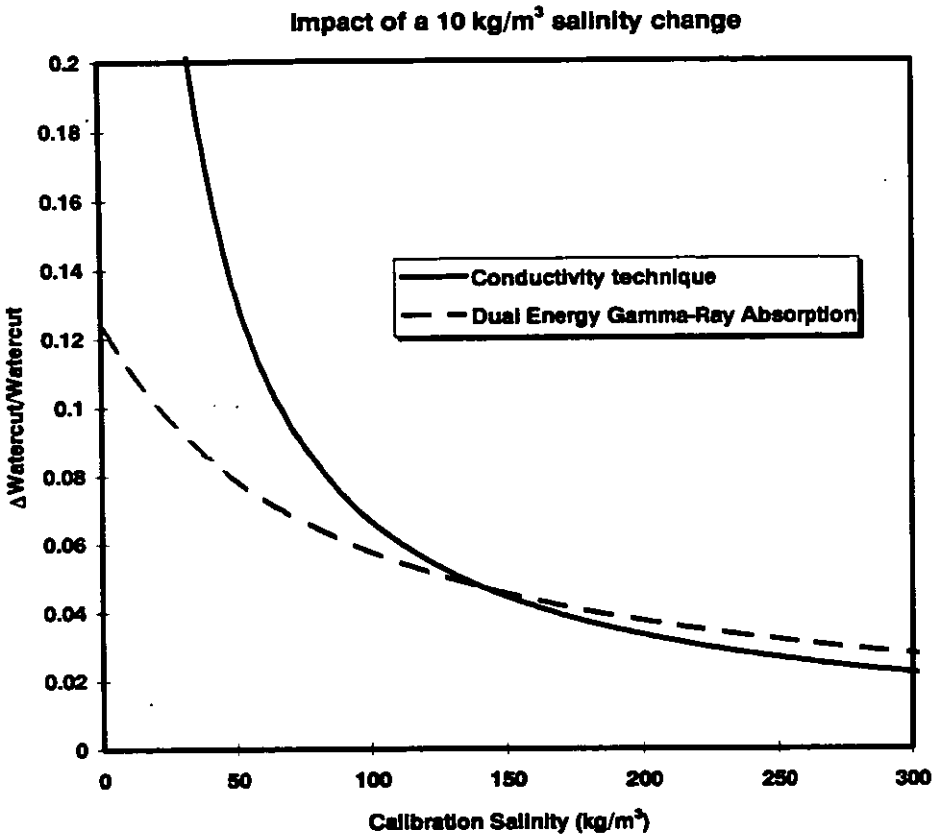

Figure 4 **The relative error in water cut, as a function of calibration salinity, due to a change in salinity of 10 kg/m³.**

Figure 4 demonstrates the sensitivity of two water-cut measurement techniques to a deviation of 10 kg/m³ from a given water-salinity calibration level. (The curve in Fig. 4 for the conductivity technique was computed under the assumption that water conductivity is linearly dependent on salinity [2] and that a Bruggeman-Hanai model was used for the calculation of water cut from conductivity [3,4]. The curve in Fig. 4 for gamma-ray absorption is a re-worked version of Fig. 6 in Ref. [5]. The nature of this problem is such that the relative error in water cut [ΔWatercut/Watercut]is the parameter to plot. This implies that the larger the water cut, the larger the impact of changing salinity will be.) From Fig. 4 it is concluded that a systematic relative error in water cut of at least 5% is to be expected for a 10 kg/m³ change in salinity, corresponding to an absolute error in water cut of more than 2% when the water cut exceeds 40%.

It is thus necessary for the manufacturer or supplier of a multiphase meter to specify the device's tolerance to changing fluid properties and to estimate on that basis a calibration frequency for a given application. In addition, the manufacturer or supplier should specify the exact procedure for in-situ re-calibration of the meter.

CONCLUSIONS

Multiphase metering hardware has been under development for over 10 years, culminating in the emergence of the first commercial products. The applications where this technology has the potential to deliver benefits have started to arise and are expected to increase. As the emphasis of oil companies' attention now switches from the development of equipment to its application, key needs have been reviewed.

These needs include the building of confidence in metering high fluid flow rates with units larger than current prototypes. In many cases, this coincides with high gas volume fractions and the requirement of accurate full-range water-cut measurements. Some applications will also involve pressures and temperatures higher than those experienced by anything built and tested to date. In this context, the accuracy levels that oil companies generally require of multiphase flowmeters have been reviewed. Although the specific requirements vary widely from application to application, they fall within the range of between 5% and 10% relative error for both the total liquid flow rate and the gas flow rate and a 2% absolute error in water cut. In certain cases, accuracy can be traded off for stability of performance. In every case, however, a manufacturer should express the error in phase flow rates relative to the phase flow rate, not to the total volume flow rate. The accuracy of water-cut measurements, in contrast, should always be expressed in terms of absolute error. In view of the confusion that currently exists, the specification and presentation of the performance of a multiphase metering system need to be standardised. Last but certainly not least, the calibration of multiphase meters also demands far greater attention.

Although the technology is admittedly immature, we believe that sufficient confidence now exists to design multiphase meter systems that will add value to emerging applications. With due attention to the needs articulated in this paper and with a general appreciation of the technical challenge and capabilities of multiphase metering, equipment developers, vendors, consultants, contractors, government agencies and field operators can all speed the technology's maturity. Further, we wish to encourage the industry to continue to strive for the ultimate target of low-cost meter-per-well systems.

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Figure 1: Two phase flow maps

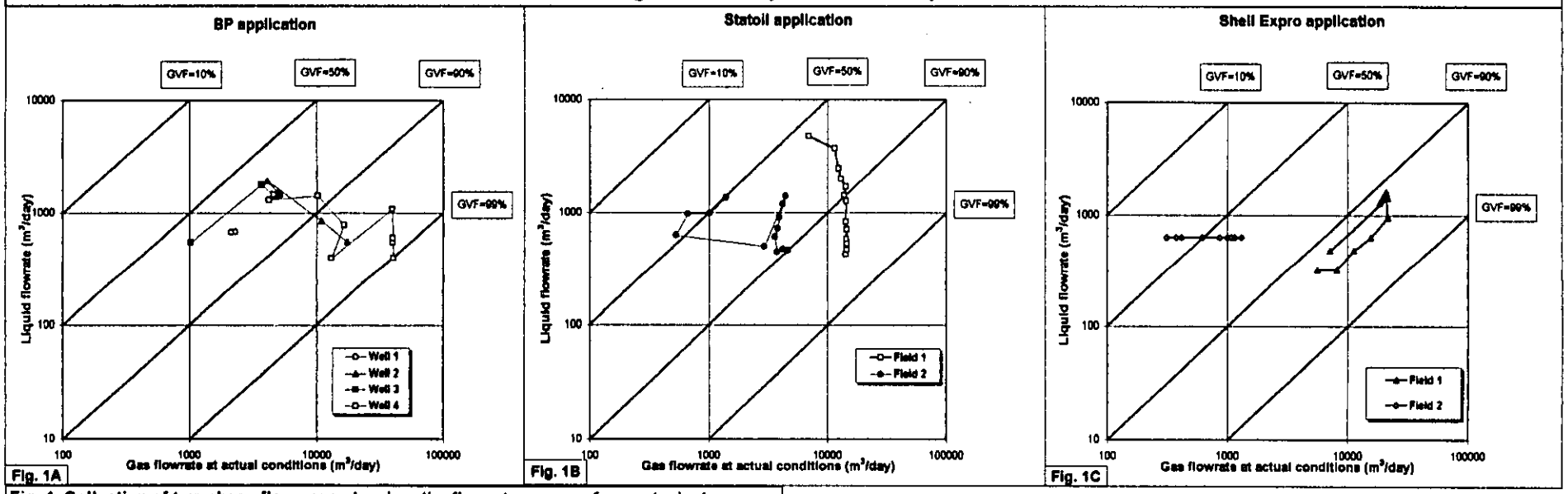

Fig. 1A Fig. 1B Fig. 1C

Fig. 1 Collection of two phase flowmaps showing the flowrate ranges of some typical multiphase metering applications. Each point represents a consecutive year.

Figure 2 Multiphase composition maps

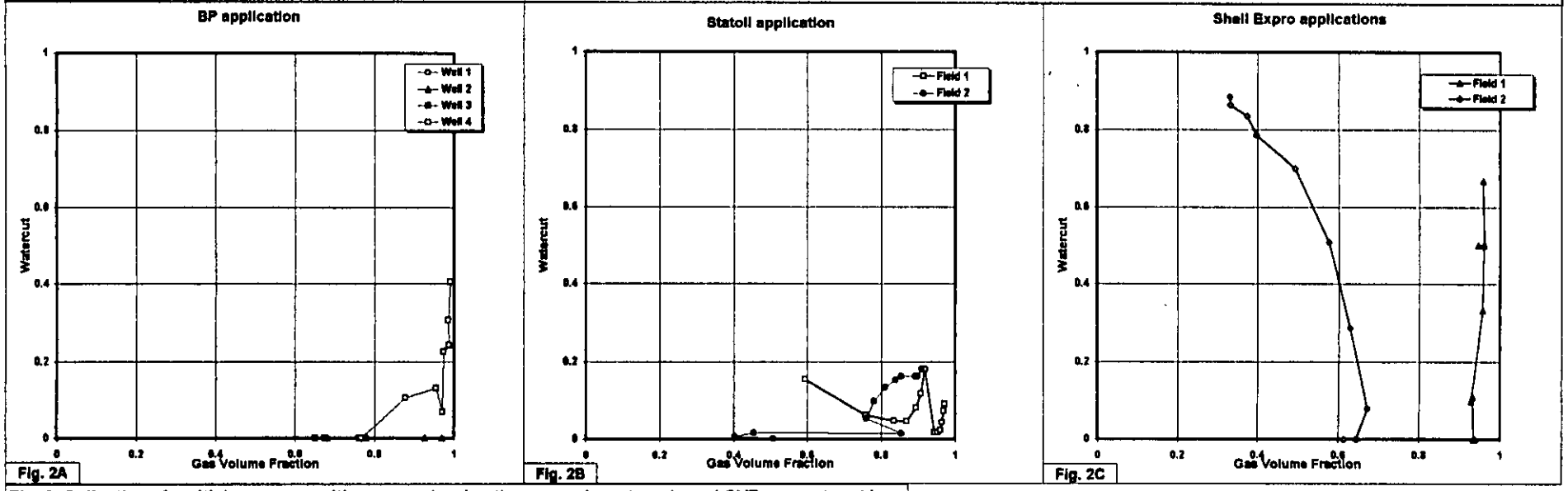

Fig. 2A Fig. 2B Fig. 2C

Fig. 2 Collection of multiphase composition maps showing the ranges in watercuts and GVF encountered in some typical multiphase metering applications. Each point represents a consecutive year.

Main Index

North Sea FLOW Measurement Workshop 1995

Paper 25:

THE NORWEGIAN TEST PROGRAMME FOR QUALIFICATION OF MULTIPHASE METERS

4·7

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The Norwegian Test Programme for Qualification of Multiphase Meters

The North Sea Flow Measurement Work Shop 1995,
Lillehammer, Norway. 23 - 25 October 1995.

The Norwegian Test Programme for Qualification of Multiphase Meters.

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1 Abstract

In 1995 the three Norwegian oil companies, Statoil, Saga and Hydro (SSH) initiated the "SSH" multiphase technology development programme. The joint programme was divided into nine different projects, one being the Multiphase Metering Project. Part of this project was a testing and qualification programme for multiphase meters. Experience gained from simultaneously testing of 4 different multiphase meters at Hydro's high pressure test facility in Porsgrunn shows very interesting results, and tells the users the different meters ability for efficient use at various conditions. The meters tested have been meters from Framo Engineering, Fluenta, Multi-Fluid and Kongsberg Offshore.

The test project took place in a new multiphase flow loop. This advanced flow loop operates at pressures up to 110 bar and at temperatures up to 140 °C. The testmatrix consist of 552 single test points at 3 different temperatures (30-60-90 °C) , 4 different pressures (20-45-67-90 bar), on watercut from 0-90% and at gas-liquid fractions between 0-99 %. Different licences in the North Sea have been participating in the project, and base cases for future field development have been used to construct a representative and transferable test matrix. Crude oil from the Oseberg field together with formation water and synthetic hydrocarbon gas have been used in the qualification work.

This paper describes the SSH co-operation, the test facility, the test programme, experience gained from the test campaign and the importance of testing meters at various conditions. The SSH project is now continuing into a new phase aiming for a subsea multiphase meter system installed in a subsea production field in 1997.

2 Introduction

The large economic potential for applying multiphase meters has been the driving force behind the various development projects supported by the oil industry the last 10-15 years. Especially the development of satellite fields will benefit from simplified metering schemes based on multi phase meters, either subsea, topside or as a combination of the two.

The applications of multiphase meter fall into one of two groups:

- WELL TESTING - Testing of a well's performance without using the test separator. The information is used for reservoir management and well operation purposes.

- ALLOCATION METERING - This will be a "fiscal" metering where the multiphase meter measurement is used as a basis for calculating taxation or to apportion production between field owners.

Today several first generation multiphase meters are claimed to be commercially available by the vendors. After a relatively lengthy development phase, the oil companies are now eager to use this cost saving technology within their field development projects. As a result of this, several oil companies have already gained valuable experience with different meters from field trials or even real commercial applications.

The experience gained from the testing of three multiphase meters at Gullfaks B shows that these meters are very efficient for well testing. The time necessary to carry out one well test was reduced to the well switching interval plus a very short test interval. At the best, the accuracy obtained was within +/- 5% of the actual flow rate for oil, water and gas. To achieve this accuracy it was necessary to calibrate the meters on site. The Gullfaks B conditions are, however, considered not to be too difficult for multiphase metering. This is due to relatively good mixing of the phases and a low gas fraction.

As seen by the Norwegian oil companies Statoil, Saga Petroleum and Norsk Hydro (SSH), two main challenges remained unsolved relative to the state-of-the-art for multiphase meters in 1992/1993:

- Provision of a sufficiently broad database for definition of the operational domain for the multiphase meters offered by the vendors, relative to the field conditions.

- Development of a subsea multiphase meter.

The basis for selection of a multiphase meter for a particular well/field had typically to rely on low pressure laboratory fluid tests, or field data for a narrow band of conditions. This was not considered good enough by SSH.

In July this year the first installation of a subsea multiphase meter took place in the UK-sector of the North Sea. This system is dependent on diver assistance for installation and maintenance. Within the SSH companies, diverless intervention was a requirement.

The SSH companies are also involved in development and testing of model based well testing methods. Testing of IDUN is now in progress at Saga's Tordis field. A similar approach has been selected by Norsk Hydro for the Troll Olje development. It is believed by SSH that a combination of multiphase meters and flow models will be parts of simplified metering concepts for several future field developments.

3 SSH - Multiphase Meter Development Project

In 1995 Statoil, Saga and Norsk Hydro initiated the "SSH" multiphase technology development programme. The overall objective is to provide cost effective field development technology for satellite fields based on the application of multiphase technology.

The joint programme was divided into nine different projects, one being the Multiphase Metering Project.

Based on the state-of -the-art in 1994, and the company's field development portfolios, it was decided to focus the activities within this project on two different activities:

1. Qualification testing of promising multiphase meters.
2. Design, fabrication and dock-testing of a system for multiphase metering subsea.

It was also decided that the project should address in detail experiences and improvements of flow model based systems (IDUN or other similar systems).

3.1 Qualification testing of multiphase meters at Norsk Hydro's Research Centre.

At the end of 1994 Norsk Hydro completed a new high pressure test loop in Porsgrunn. This loop was intended for various multiphase and process technology

research projects. The availability of a high pressure multiphase flow loop was invaluable for the SSH subsea metering development project, because the rig offered unique possibilities for creating real flowing conditions with large parameter variations. The pressure range was 10-110 bar, the temperature range 20-140 °C and the gas-liquid fraction could be varied from 0 - 100 %. The fluids in the loop should be stabilised crude, synthetic hydrocarbon gas and formation water. It was decided in the autumn 1994 that the test rig should be modified to include test facilities for multiphase meters. The reference measurements were upgraded and a dedicated test section was built.

Four vendors of multiphase meters were invited to participate in the test programme. No multiphase meters from vendors outside Norway were known to SSH to have sufficient potential relative to the requirements for the subsea meter.

The vendors of multiphase meters participating in the test were:

- Fluenta
- Framo Engineering
- Kongsberg Offshore
- Multi-Fluid International

All the vendors claimed they could provide multiphase meters which could measure from 0-100 % of all the three phases (limitations in gas-fractions up to 90 - 95 %)

3.2 Design and fabrication of the subsea multiphase meter.

Based on the qualification test results and other relevant criteria, one or several of the tested meters will be selected as basis for the design and fabrication of the subsea multiphase meter. The development of the subsea meter is estimated to take 1.5 years. The final project phase includes dock testing of the subsea multiphase meter and a long term field test of the meter at an offshore platform.

4 Objectives

The objectives for the qualification test project can be summarised as follows:

- To test 4 commercially available multiphase meters that are candidates for being further developed into subsea meters.

- To explore their application envelope and the accuracies under realistic multiphase flow conditions relative to the requirements of field development projects participating in the project.

- To inform field development projects about the performance of multiphase meters. To recommend multiphase meters to be used for Statfjord Nordøst-segment, Gullfaks Satellites and the Åsgard fields (Smørbukk, Smørbukk-Sør and Midgard).

At the same time, the extensive test will provide the vendors with data for further development and improvements of their meters. A major objective is, however, to develop one or several of the existing multiphase meters into subsea meters.

5 Test facility Hydro Research centre, Porsgrunn

5.1 High pressure test loop for multiphase research

5.1.1 The Multiphase Flow loop

The Multiphase Flow Loop (MPFL) at Norsk Hydro, Research Centre Porsgrunn is a circulating test loop for hydrocarbon liquid (crude oil or condensates), hydrocarbon gas and formation water operating up to 110 bar and 140 °C.
The fluids used are recombined to specified composition. Special attention has been given to prevent system contamination by lubrication oil from pumps and compressor.
The pressure in the loop is controlled by a gas accumulator. The flow rates of the individual phases are measured by flow meters and controlled by variable capacity pumps. The circulation capacity of liquid is maximum 60 m^3/h, while the maximum gas capacity is 205 Am^3/h.
The temperature of the fluids are controlled prior to mixing of liquid and gas. All equipment, including all pipes, have electric heat tracing ensuring stable temperature. Simplified flow diagrams are enclosed in figure 1 and figure 2.

After establishing three phase flow the fluids enter the test loop. The loop has a length of 2 x 60 meter with a pipe having a diameter of 77.9 mm. At the end of each of the two loop lengths there are test sections. The multiphase flow meter test section is located at the end of the first length and a test section area equipped with several types of instrumentation adapted for multiphase technology is located at the end of the second length. The instrumentation area includes a traversing sampling valve, measurements of viscosity, capacitance/conductance, shear forces, pressure drop,

wall and fluid temperature, density, flow regime detection, corrosion and wall wetting.

5.1.2 *Applications*

The MPFL has three main areas of application; separation studies, multiphase technology (i.e. fluid dynamic-, corrosion-, emulsion-, foam-, wax- and hydrate-) studies and equipment testing and qualification.
In addition to the test sections of the loop also the MPFL separator has been given a special design making it well suited for experiments, mainly separation tests and equipment testing.

5.1.3 *Test of multiphase flow meters*

48 meter downstream the mixing point of the fluids at the very beginning of the test loop, the test section used for the test of multiphase flow meters was connected as a parallel flow line.
In the test section which had the same diameter as the flow loop the multiphase flow meters had a serial installation. Each meter installation was thoroughly discussed with the suppliers before making the test section design layout.

The KOS meter was decided to have a horizontal installation at the same level as the test loop and was placed at the very beginning of the test section, implying a horizontal pipe length of approximately 600 pipe diameters with one 90° bend upstream the meter. 4 meter downstream the KOS meter the FRAMO meter had a vertical installation with inlet at the upper side and with bottom outlet. The next meter installed was the FLUENTA meter which had a vertical installation with upward flow. The distance between the FRAMO and FLUENTA meters was 15 meter, out of which 12 meter was straight and horizontal pipe. Immediate downstream the FLUENTA meter a PETROTECH sampler was installed. The sampler was not part of the test, however, the installation was done to assist the development of a multiphase sampler. The final installations were a MaReMi mixer from SINTEF, Multiphase lab. and the MFI meter. The MFI meter also had a vertical installation with an upward flow direction. The pressure drop signal from the MaReMi mixer were transferred to, and used by, the MFI meter.

5.1.4 *Reference meters*

The multiphase meters measure flow rate through the meter at actual conditions. Hence, reference flow rates are the actual flow rates of each phase oil, water and gas, at the location of each specific multiphase flow meter. Flow rate of fluid fed to the test section is measured by separate flow meters for each single phase of oil,

water and gas. These flow meters are installed upstream of the oil/water and Liquid/gas mixing points. Pressure and temperature is measured at the reference flow meters, in the test section, and at each multiphase flow meter.

The oil phase (outlet from separator) may contain several % of water dispersed. A water-in-oil monitor was installed in the oil leg to monitor the water content. However, this meter was never working satisfactory, and water content was determined by taking manual test points for analysis. The uncorrected reference flow rates for oil and water are corrected for water in the oil phase. The water phase contains negligible amounts of oil.

Flow meters and pressure/temperature transmitters, and their associated instrument loops, used to calculate reference flow rates were calibrated, traceable to national or international standards.

Reference flow meters had to be selected with a view to obtain sufficient functionality, reliability, accuracy and turndown. The meter had to comply with piping class requirements of -30 to +150°C and up to 125 bar pressure.

The reference flow meter on gas was a INSTROMET turbine gas meter type SM-RI-G160-80-130-K. The overall accuracy of gas measurement has been calculated to be within an uncertainty of 0.85 %.
The reference meter on crude oil was a KRAL positive displacement meter model OMX 68. The overall accuracy of oil measurement has been calculated to be within an uncertainty of 0.66 %.
The reference water meter was a DANIEL "PT" liquid turbine meter catalogue 1406-1P 2". The overall accuracy of water measurement has been calculated to be within an uncertainty of 2.02 %.

The gas reference meter was certified with natural gas at 32 °C and 50 bar by Nederlands Meetinstituut (NMi), Silvolde. The liquid reference meters were certified by Con-Tech a.s, Stavanger. The certification was done at the same temperature and pressure and with the same crude oil as used the test program.

5.1.5 PVT Calculations

In the MPFL the three reference meters are located close to the separator and not in the test section for the multiphase flow meters. Consequently there are differences in pressure and possible minor differences in temperature between reference meters and multiphase meters in test.
To calculate the correct deviation between reference rates and multiphase meter rates the reference rates are recalculated to multiphase meter conditions.

Hence, each multiphase flow meter will have its own, specific reference flow rates, reflecting the operating conditions at that particular flow meter.

The recalculation takes the following changes into account:

- Change of fluid densities due to change of pressure and temperature.
- Change of gas and oil rate due to possible condensation of gas.

5.2 Fluid properties

5.2.1 Physical properties

The composition of the hydrocarbon gas through the test program was as follows: 96 - 98 % methane, 0.3 - 0.6 % ethane, 0.5 - 0.3 % propane, 0.3 - 0.5 % $C4_+$ and 1.8 - 1.0 % nitrogen. The exact composition is dependent on actual pressure and temperature and mass transfer between the crude and the gas at each test condition.

The crude oil used in the test was taken from the test separator at Oseberg A when operating at low capacity without addition of oil field chemicals.

The water used in the test was made up from purified fresh water added 5 % NaCl, 0.5 % $MgCl_2$ and 0.5 % $CaCl_2$, i.e. totally 6 % salt in water.
Measured conductivity in water: 92 mS/cm at 20 °C.
At the end of the test the salt content was reduced to approx. 5 % causing a reduction in conductivity to 80 mS/cm.

5.2.2 Real system vs. model system

Further experiments on flow technology on behalf of the SSH group will bring more knowledge of the characteristics of real hydrocarbon system related to multiphase flow. However, based on the test we find differences in foaming -, emulsion - and in flow characteristics compared to an Exxsol based model system. A real hydrocarbon system (Oseberg crude oil) forms more stable foam and more stable and viscous emulsions at low temperatures. We also found that dispersed flow was established at lower velocities than in a model system, implying a more easy mixing of gas and liquid.
Based on the observed foam stability, causing liquid entrainment in separator gas exit, addition of defoaming agent was found to be necessary.

5.2.3 Flow regimes

By using a vertically installed high frequent measuring gamma densitometer the average density of the multiphase flow was measured vs. time. The instrument which is installed in the instrumentation area of the loop has a location corresponding to the first multiphase meter, i.e. at a distance equivalent to approximately 600 pipe diameters downstream last installation. The densitometer configuration is adapted for identification of flow regimes of gas/liquid systems and the main purpose is to identify regimes with and without slug flow.
The following types of flow regimes were observed: Slug, slug/dispersed, annular, stratified, stratified/wavy, stratified/dispersed and dispersed.
The tendency is to dispersed flow at relatively low rates and to increased slug flow with decreasing pressure and increasing watercut.

5.3 Data processing

The outputs from each multiphase flow meter were rates of gas, oil and water and their separate measurements of temperature and pressure.
The FLUENTA and the MFI meters gave two sets of rates; rates based on pressure drop (MaReMi mixer on the MFI meter and venturi on the FLUENTA meter) and rates based on cross correlation.
All rates were expressed as m^3/h, temperature in degrees Celsius and pressure in bar.

Each test point was defined to last at least 15 minutes with stable flow conditions. Every 10 second updated signals were imported from the Multiphase meters to the Plant Information logging System (PI). Consequently each test point consisted of at least 90 individual meter readings. The average value of these numbers were used for data processing in Excel. To observe abnormal variation in readings the standard deviation of each reading were calculated. All meter readings having high standard deviation have been controlled, both by looking into each value logged in PI and by looking into data logged on the correspondent individual multiphase flow meter.
The results and the belonging calculations from the test are separately stored in Excel version 4.0 tables. Each meter have five tables of 40 to 220 rows and of 80 to 90 columns.

6 Test programme

The test program included totally 552 test points at different combinations of pressure, temperature and flow rates. The program was performed at four pressure levels; 20, 45, 67 and 90 bar, at three temperature levels; 30, 60 and 90 °C, at gas superficial velocities from 0 to 12 m/s and at liquid superficial velocities from 0.1 to 2.5 m/s implying watercuts from 0 to 90 % and GORs from 0 to 99 %.

Basis for the test matrix was data from the participating field development projects/ licenses wrt. expected well/flowline flow rates, gas volume fractions, watercut etc. over the lifetime of the fields.

Relative to the field conditions, the new test facility at Norsk Hydro's plant at Herøya in Porsgrunn has some limitation wrt. maximum flow rates for gas and liquid flow. These limitations were not fully known prior to the test because Norsk Hydro did not have any experiences with operating the rig with crude oil. The commissioning of the test loop took place in December 1994 to February 1995, with diesel oil and nitrogen.

6.1 Test matrix

The main technical data for the test rig including the test section with multiphase meter installed are as follows:

- Temperature range: 4 - 140 °C
- Maximum pressure: 110 bar
- Diameter of test loop: 3"
- Capacity of water: 40 m^3/h (2.4 m/s)
- Capacity of oil: 40 m^3/h (2.4 m/s)
- Capacity of gas: 205 Am^3/h (12.3 m/s)

Due to the capacity of the different pumps in the test rig the maximum pressure drop was 6 bar. The section where the multiphase meters were installed created a pressure drop which was not taken into account when specifying the maximum flow rate. The maximum gas flow rate during the multiphase meter test was 204 m3/h. The maximum liquid flow rate was found to be 42 m3/h. The Oseberg crude was found to be oil continuous for watercuts below 65 % and water continuous for watercuts above 65 %.

The flow patterns (flow regimes) experienced during the test depended on pressure, fluid properties and superficial gas and liquid velocities. The pipe length (no. of diameter) upstream the meter section was close to 50 m (> 600 D). This means that fully developed flow patterns were established upstream the meter test section.

Since the pressure will have a strong influence on the flow regimes, it was decided to use the majority of the 550 available test points at 20 bar (35%) and 90 bar (35%). At 20 bar the slug envelope was significantly larger than at 90 bar. This is mainly due to a smaller density difference between the liquid and the gas at higher pressures. In order to investigate if the meters' accuracy is significantly influenced by temperature, three different temperatures 30, 60 and 90 °C, were chosen.

The initial tests showed that there were significant difference between the 20 bar test points and the 90 bar test points wrt. performance of the multiphase meters. It was therefore decided to add two additional, but smaller, matrixes at 45 and 67 bar. These additional tests were conducted at a fixed temperature of 60 °C. The test programme was concluded with some special tests for repeatability, bypassing of the Framo-mixer and investigation of the influence of altering the salinity of the formation water.

The test was divided into 11 different test series. In each series the superficial velocities and watercut were changed. All possible flow regimes were then covered by the test.

Series	Pressure (bar)	Temp. (°C)	Special test	No. test points
I	20	60		158
II	90	60		158
III	20	90		44
IV	90	90		49
V	20,90	30	(low temp)	26
VI	45	60		32
VII	67	60		58
VIII	67	60	(low salinity)	10
IX	67	60	(Repeatability	8
X	67	60	(Bypass Framo)	4
XI	67	60	(Vendors wish)	5

Table 1: Test programme

Tests with a very low watercut (0 to 1%) were also included. This was done in order to simulate a water breakthrough in a well. This would enable us to see if the meters could detect this phenomenon very early.

Previous experience with multiphase meters has shown that varying the salinity of the water strongly affects their performance. A special 10 point test sequence was therefore carried out in order to investigate this phenomena. 10 test points in the 67 bar matrix were repeated with a salinity reduced from 6 wt% to 5 wt%. This salinity change was meant to represent the situations in wells when the produced water is changing from formation water to a mixture of formation and injected water.

6.2 Calibration and meter modifications

The vendors agreed that after calibration of the meters, no modifications were to be made on the meters during the 20 bar test period. Before switching to 90 bar, each vendor was allowed to implement minor changes and to recalibrate the meter with upgraded density information.
In separate meetings with each vendor prior to the testing, the vendors accepted this procedure. A test agreement was then signed by all the companies. Furthermore, it was agreed that any subsequent modification should be applied for by the vendors and approved by SSH before implementation.

6.3 Presentation of test results

It is very important to present the results well arranged since the amount of test data is very large. The main guidelines for the presentation can be summarised into the following:

- The results from each vendor is presented separately.
- The results is divided into pressure level. Three presentations wrt. oil, water and gas flow rates are given for each pressure level.
- Differentiation is made between oil- and water-continuous flow.
- The flow meters results are illustrated in two different ways on the same page to show performance. The first method is a XY plot, where the abscissa represent the reference while the ordinate represent the flow meter (XY plot). In the second method the ordinate is the absolute difference between the meter and the reference.
- 10 % uncertainty band is superimposed on each plot to illustrate the accuracy of the meter.
- A method for more detailed evaluation is prepared. This evaluation shows the meters performance and accuracy regarding gas-volume fraction, watercut, actual fraction, total liquid flow and water cut measurement.

Examples of presentation of test results are shown is fig 3. The results are evaluated in 5 different levels. In level 1 the flow rates for each phase are shown. Level 2 shows the total liquid flowrate and the deviation in watercut. In level 3 the relative deviation for oil, water and gas are presented as a functiion of gas fraction. Level 4 and 5 are also showing relative deviation for each phase as a function of watercut (level 4) and as a function of the actual phase (level 5).
No detailed test results will be presented in this paper. It is difficult to present results from such a large test, including meters from four different vendors, in a representative and complete manner. The results are owned by the license groups funding the test.

7 Experience gained in the test programme

The results obtained in the Porsgrunn test have shown that it is very important to demonstrate the different meters performance over a wide range of operating conditions.

Testing at different pressure levels above 20 bar have shown that some of the multiphase meter principles are pressure/flow regime dependent whereas other principles have proved to be more or less pressure/flowregime independent. For one of the meters the test has revealed that the meter is not yet applicable for high pressure applications. For the three other meters the best results are obtained at the highest pressure levels in the test. The temperature variations are not showing any significant impact on the meters performance.

For several of the meters, important improvements have been made during and after the test period based on the experience obtained. Some of the vendors have implemented or improved their flow models to compensate for velocity difference between liquid and gas (slip) etc. These models have to be pressure and site independent to prove their efficiency.

Use of differential pressure devices to measure flow velocity have been proven to be very efficient for most of the test conditions. It is also seen that the velocity results are generally very good at as low pressure drops as 30 - 40 mbar.

The testing has demonstrated the different meters performance over a large range of conditions. The most important experience is maybe that the meters can be used at gas-volume fractions as high as 95-96 % with satisfactory results. For the electromagnetic meters it is today more difficult to measure in water-continuous flow than in oil-continuous flow. Only one of the meter has demonstrated that it can detect a water break-through in a well. That is, a minor change in watercut from 0 % till 2 %. To obtain this sensitivity it is of key importance to calibrate the meter in a proper way.

The testing has demonstrated, for three of the meters, an accuracy levels within a 10 % confidence interval for the majority of the test results for all three phases. This is satisfactory knowing the wide range of test conditions going from 0 % gas to 98 % gas etc.

Although the results are generally positive, the testing and the first experience after commissioning of the meters have revealed weak features for some of the meters. It is important to concentrate work on the calibration procedures. It is not a practical way in field applications to modify calibration constants looking at results from the

reference measurements. We do expect that we at the end of this year will see improved meters from all vendors compared to the versions tested in Porsgrunn!

8 Conclusions

The testing of four commercially available multiphase meters has been very important for the three Norwegian oil companies Statoil, Saga and Norsk Hydro in their efforts to qualify and select multiphase meters for key applications. After the test campaign, the basis for selection of a multiphase meter for a particular well/field can now rely on high pressure test results over a wide range of conditions. These results, together with previous field experiences demonstrate that 3 of the meters have reached a maturity level that is satisfactory for the oil industry to consider the technology qualified and applicable for both topside and subsea applications.

For 3 of the meters the results showed a generally good performance, especially at high pressure levels. The meters are different and they are all having strong and weak features. When selecting multiphase meters, the test results will be compared with the actual predicted production profile for each well/field.

The SSH co-operation on Subsea Multiphase Meter Development is now entering into the next phase aiming for a subsea multiphase meter to be implemented early 1997.

Acknowledges

The following field development projects/licenses are supporting the programme:

- **Åsgard** (Smørbukk, Smørbukk Sør and Midgard).
  Partners: Statoil, Mobil, Neste, Agip, Total, Norsk Hydro, Saga, Deminex.

- **Statfjord Nord** (PL037).
  Partners: Statoil, Mobil, Esso, Conoco, Shell, Saga, Enterprise, Amerada Hess.

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  Partners: Statoil, Saga, Norsk Hydro.

- **Vigdis**
  Partners: Statoil, Saga, Esso, Idemitsu, Norsk Hydro, Elf, Deminex, DNO.

References

1. Økland, O., Berentsen, H., Moestue, H., Kjølberg, S.A.: "Testing of Multiphase Meters . Statoil, Saga, Hydro" (Classified internal report Statoil F&U UOD 95035), September 1995
2. Communication and test evaluation reports from the vendors:
   - Framo Engineering AS
   - Fluenta AS
   - Kongsberg Offshore AS
   - Multi-Fluid Int. AS

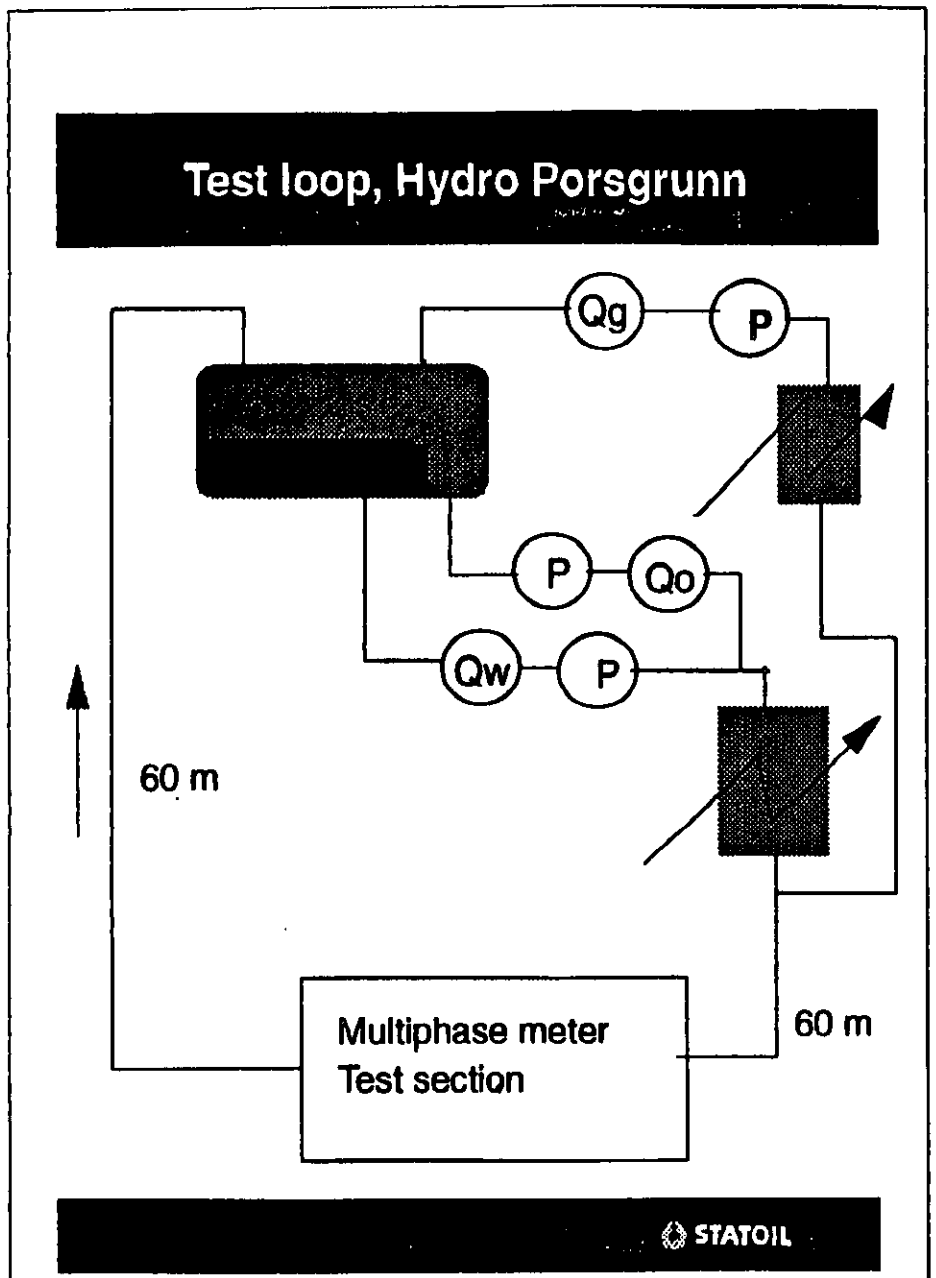


Fig 1 Multiphase Test Loop

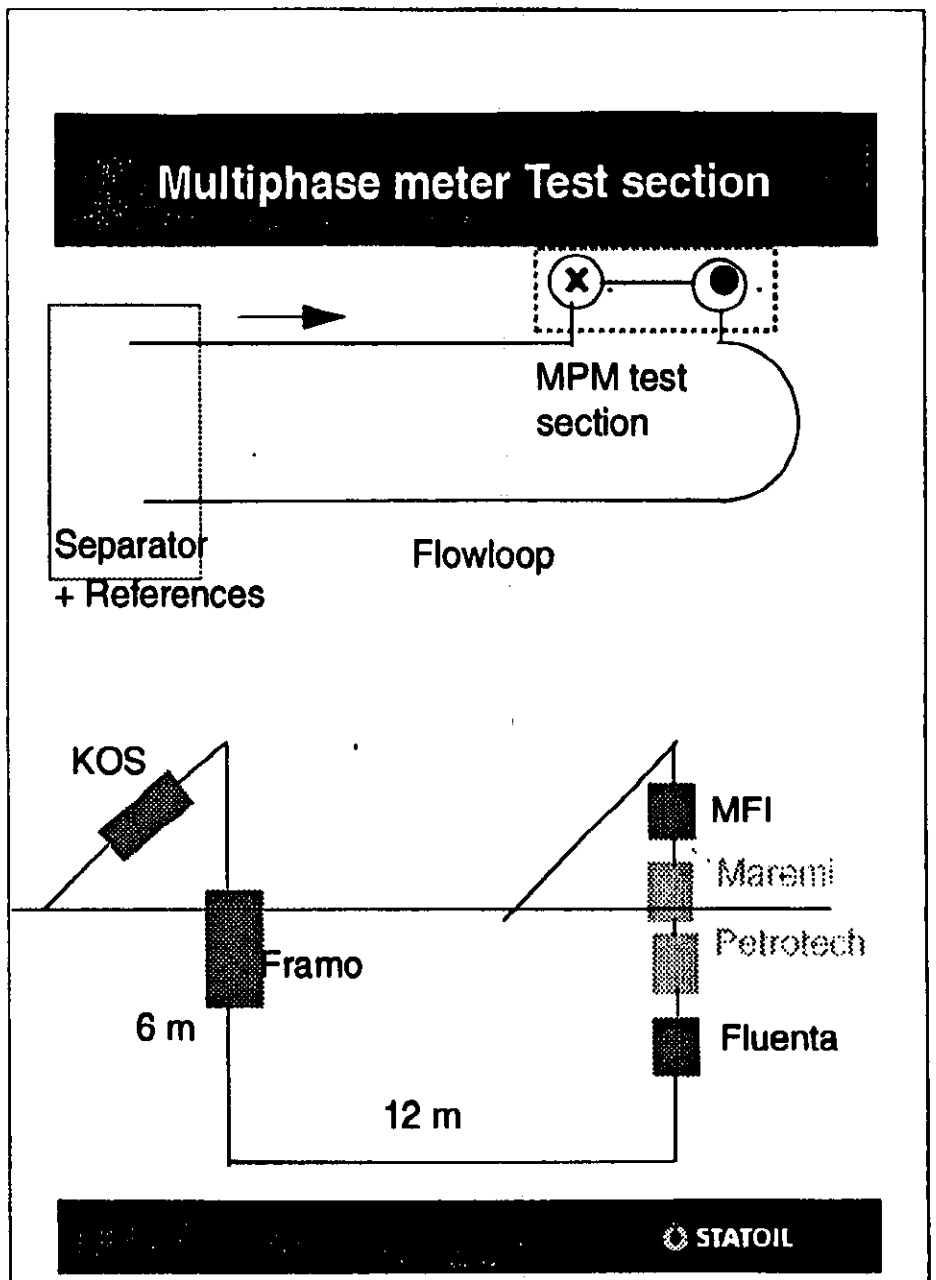
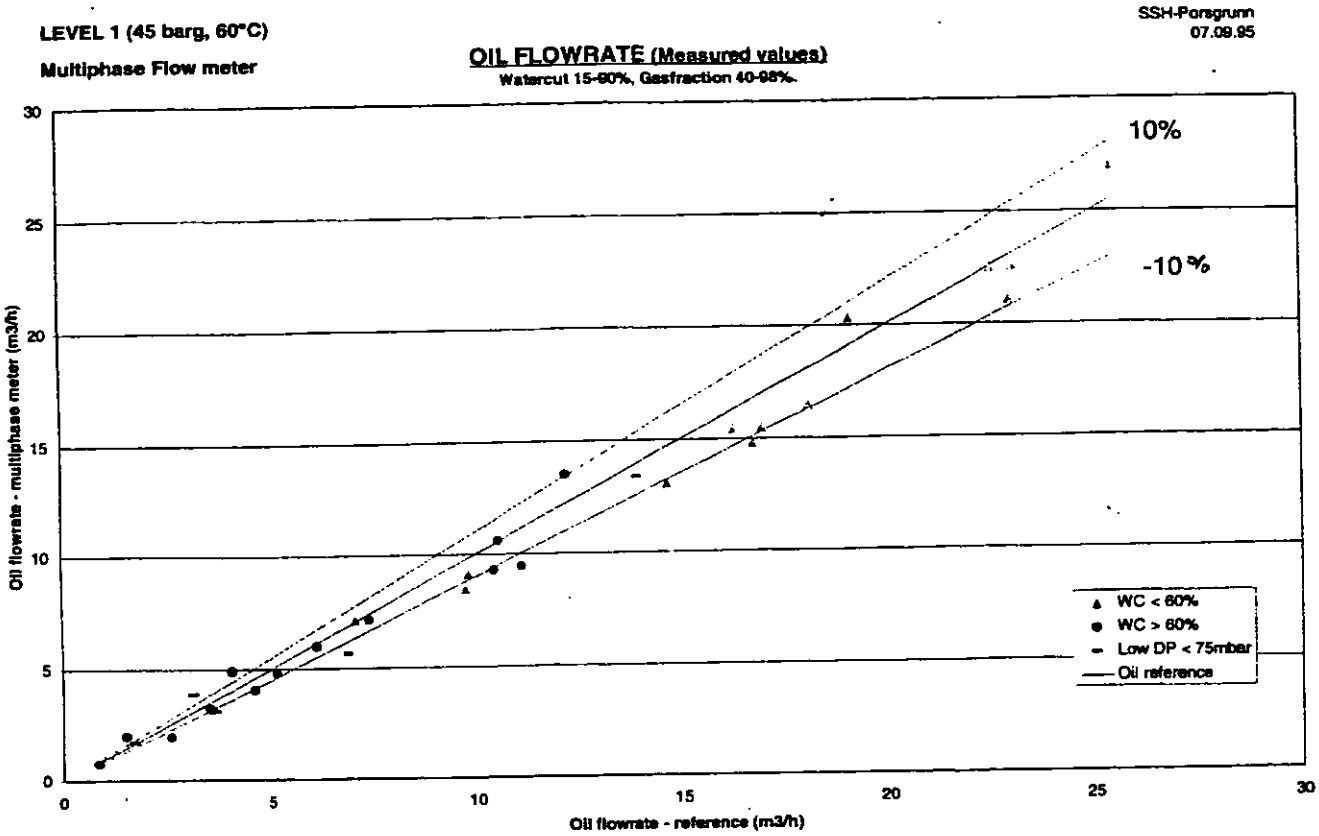


Fig 2 Multiphase Meter Test Section



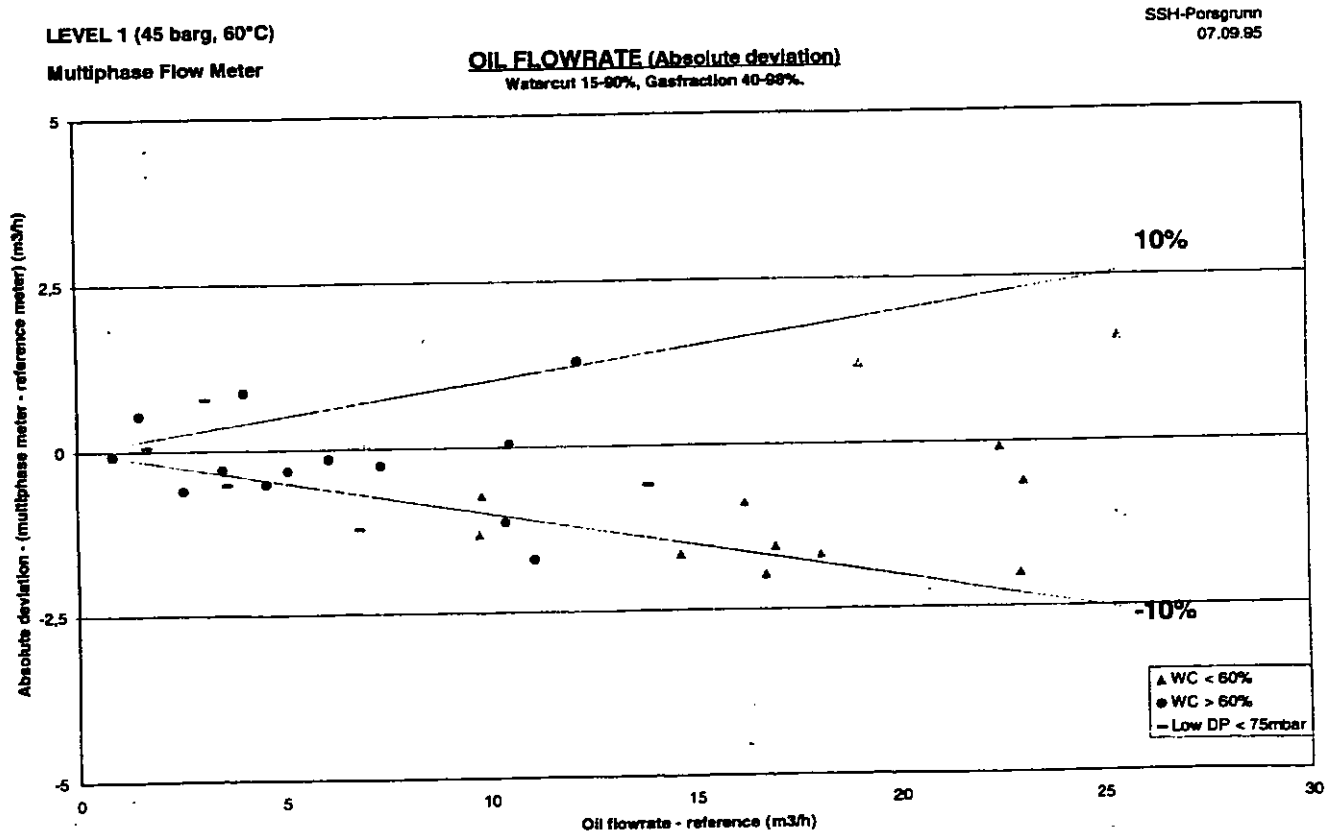
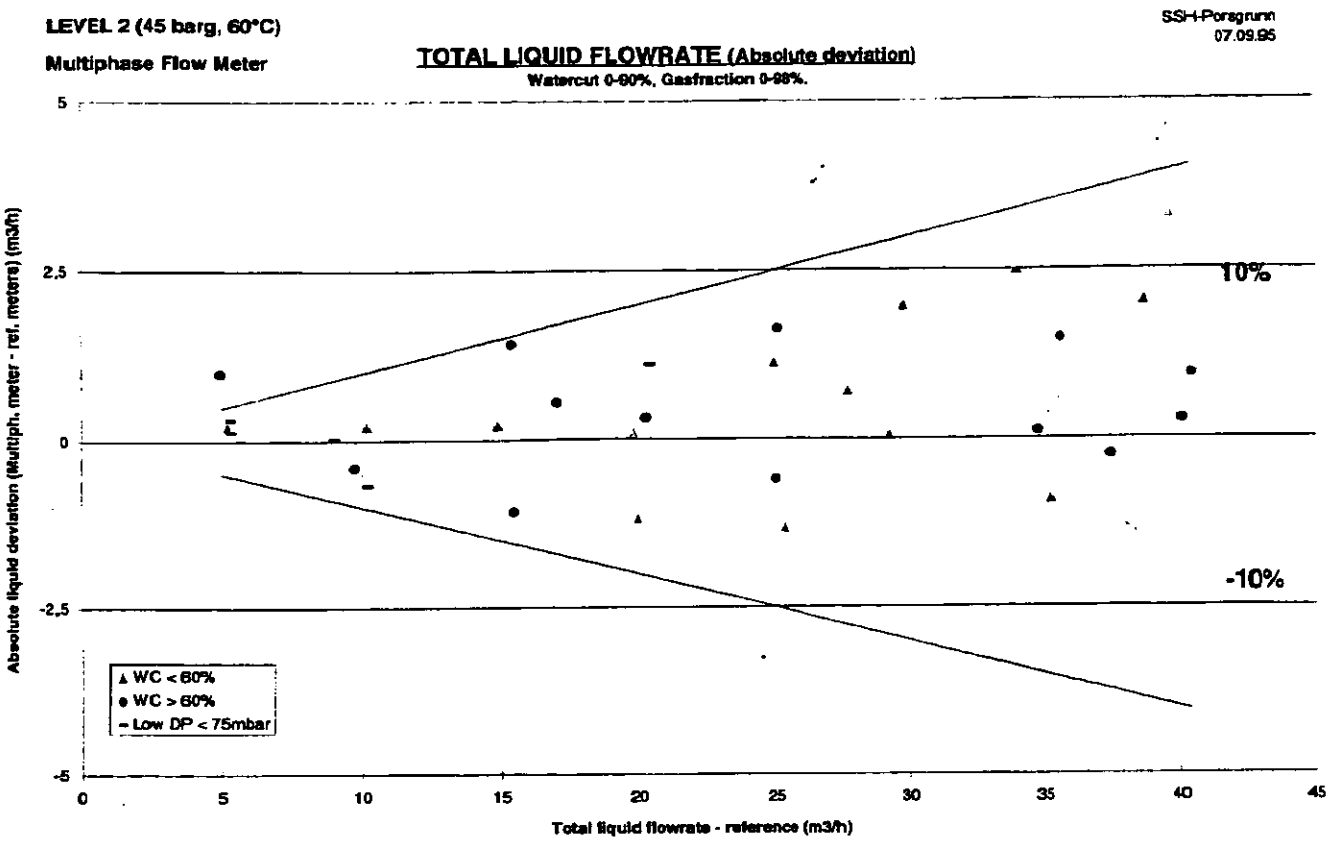


Fig 3a. Presentation of test results Level 1



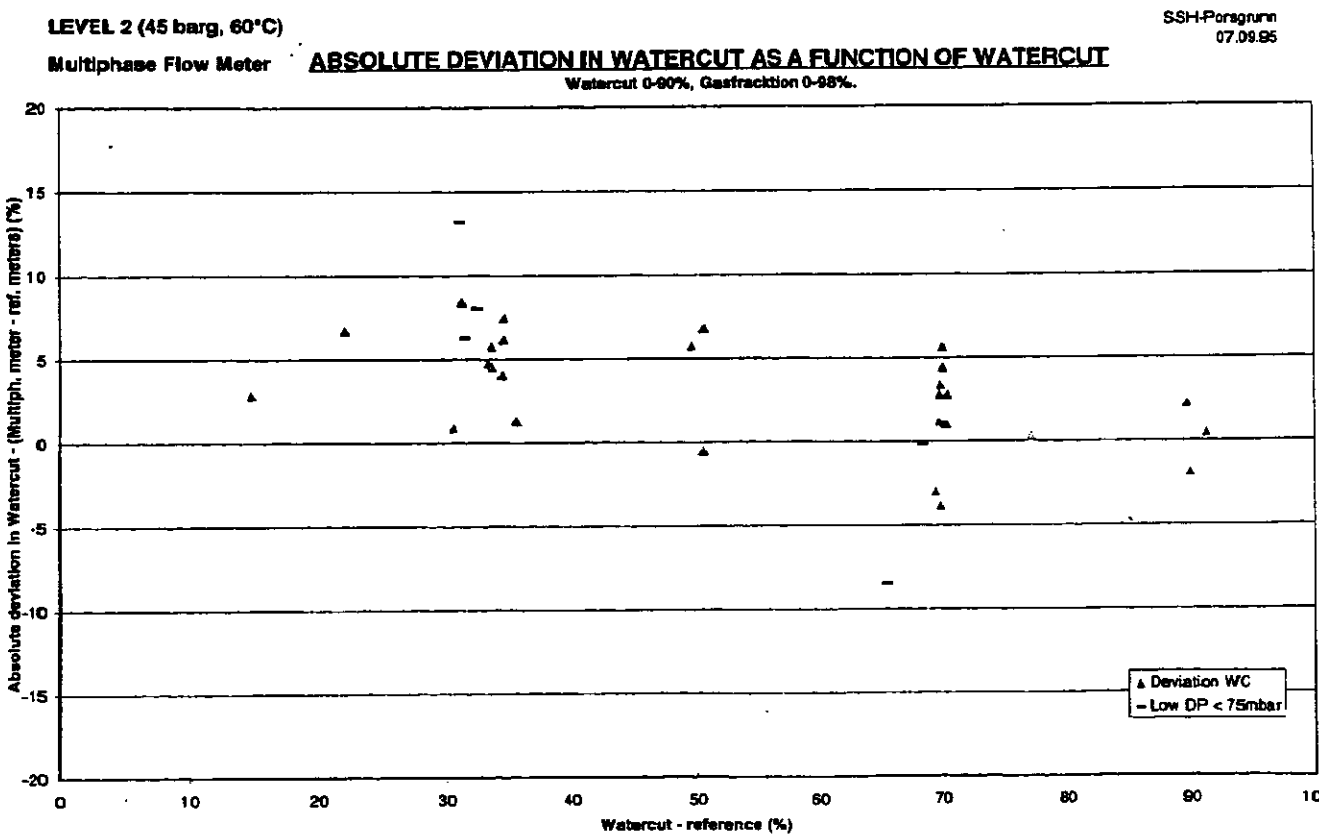
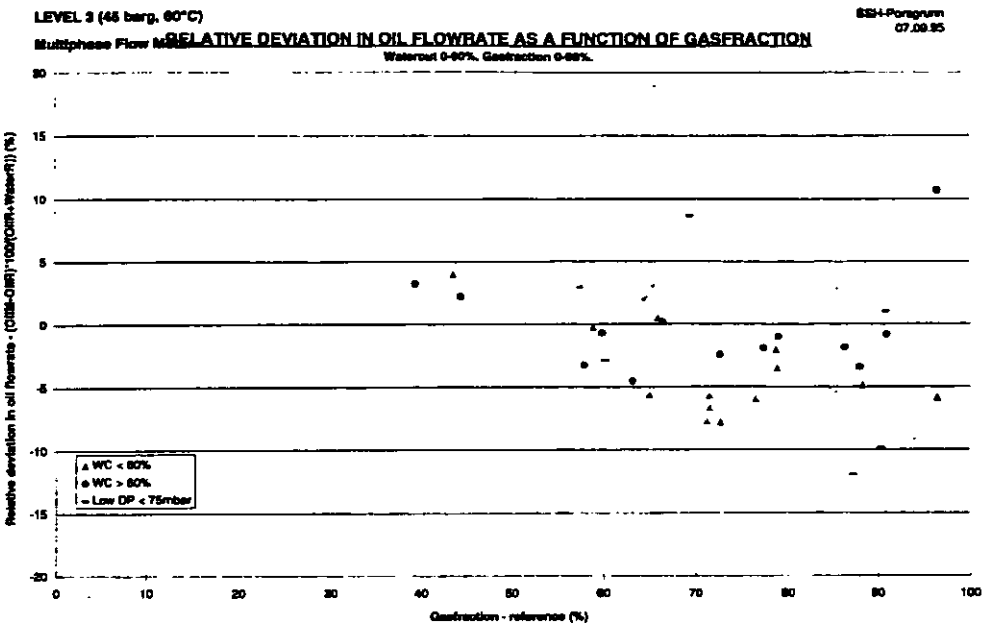
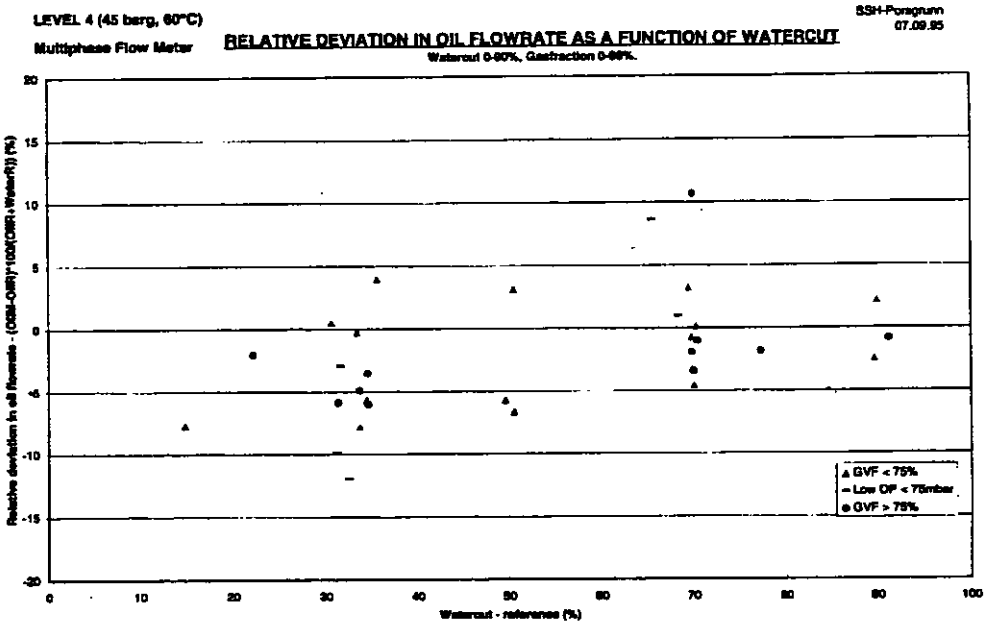


Fig 3b. Presentation of test results Level 2





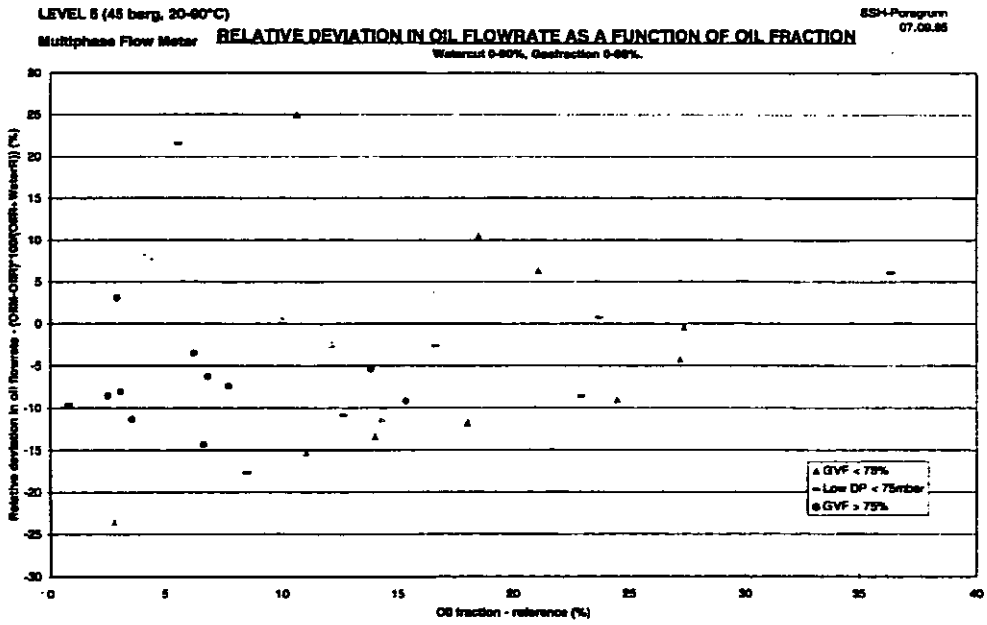


Fig 3c. Presentation of test results. Level 3 - 4 - 5

Main Index

North Sea FLOW Measurement Workshop 1995

Paper 14:

ULTRASONIC METER: IN-SITU SKID MOUNTED FLOW TESTING

5.1

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ULTRASONIC METERS

In-Situ Skid Mounted Flow Testing

ABSTRACT

This paper is a continuation of the work and results presented last year by Klaus Zanker (Ref 1) and Karen Van Bloemendall (Ref 2) at the North Sea Flow Measurement Workshop, Peebles; Scotland, on behalf of the Ultrasonic Meter (USM) "Ultraflow" Consortia projects and the developments presented by Michael Reader-Harris (Ref 3) at San Antonio earlier this year at the AGA Flow Symposium on behalf of the Flow Headers Consortium.

These projects covered the development of :

i. a wet gas multipath ultrasonic meter using a modified dry gas meter;

ii. an investigation into the installation effects of the meter;

and iii. an investigation into the flow properties downstream of a variety of flow conditioners when inserted in meter tubes downstream of a flow header.

Using the results from these projects and two prototype six inch meters a compact metering skid has been designed, built and flow tested which will be used on 'wet' process gas. This skid will be installed on Phillips Petroleum Co UK Limited's Hewett 18/29C platform in the UK sector of the North Sea to meter gas from the Dawn subsea development.
The results of the flow testing on dry gas under different flow conditions are reviewed in this paper.

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C O N T E N T S

1.0 DAWN DEVELOPMENT

1.1 INTRODUCTION

Dawn is a single subsea gas satellite located some 6 miles from Phillips' unmanned Hewett Charlie platform in the Southern sector of the North Sea. It will be produced onto the Hewett, free liquids (condensate and water at 5-10 bbl/mmscfd) will be separated out, and the gas metered and commingled into the Hewett gas. The Hewett gas is committed under contract, so there is a need to meter the Dawn gas in order to allocate it on arrival at the Bacton processing plant where it will be sold to another customer. The gas on Hewett is not dehydrated or metered and it is necessary to meter the Dawn gas in the 'wet' state.

1.2 METERING OPTIONS

As the project commenced it was evident that only two or three options were available for metering the produced gas. These were :-

1.2.1 Conventional gas processing and drying prior to metering with orifice meters. However, due to the weight and cost constraints and the additional risk to personnel because of increased maintenance, it was disregarded.

1.2.2 Wet gas metering utilising a Venturi and the Jamieson modified Chisholm equation as part of the flow algorithm. The limitations are the Venturi turndown ratio - which is significantly less than the ultrasonic meter - and the need to know the liquid content in the gas (from regular well tests). As a result this method was not pursued further.

1.2.3 Wet gas metering using the newly developed and tested wet gas ultrasonic meters. Based on the results produced in testing and the availability of the prototype test meters, this option was selected.

In attempting to meter 'wet' gas, it is essential to remember that there are two types of meter currently available - momentum meters (which measure DP,ρv^2) and velocity meters. Wet gas which has say, 1% by volume of liquid at 60 barg, will have a mass difference of around 10% - and it is this difference which creates large errors when using a DP device in measuring 'wet' gas.

1.3 METERING APPROVALS

The UK's Department of Trade and Industry, Oil and Gas Office provide guidance and approval for systems used for allocating UK petroleum revenue taxes. In general, provided "good oilfield practice" is used there are few problems. When approached with new technology or dramatic changes to established practises, the Department requires the Operator to establish a period in which the technology can be evaluated and a fall back position which can be utilised if the technology is unsuccessful.

1.0 DAWN DEVELOPMENT

1.3 METERING APPROVALS (CONTINUED)

In this respect, the wet gas ultrasonic meters have been accepted for evaluation with a programme to monitor the meters' performance using a dry gas calibration of the skid, a data acquisition package for long term monitoring and the ability to place the meters in a series mode of operation (see Figures 1 and 2), in order to carry out checks on the individual meters' performance, during the evaluation period.

1.4 SKID DESIGN

To flow the required rates (60 mmscfd) in the initial production period at the pressures available for entry into the Hewett systems, two 6 inch meters are required. These have been provided by utilising the two prototype meters manufactured for the Wet Gas Consortium. The meters are installed in a parallel configuration , (see Figures 1 and 2), with an optional 'transfer' line between the output of one meter to the inlet of the second.

In considering the skid 'footprint' available, it was certain that the available meter tube lengths would be short, and with the use of the 'transfer' line to flow in series, the flow profiles would probably be unacceptabe. To overcome the additional uncertainties due to installation effects presented by K.Van Bloemendall (Ref 2) the results of the "Flow Header" consortium work (Ref 3) were reviewed. The optimum design from the Flow Header project work would have been to install a plate conditioner 4D downstream of the header, with the meter 10D downstream of the conditioner and a 3D for USM (5D for an orifice) discharge pipe to the outlet header. This would have given a 17D overall meter tube length. However, the need to install a 'transfer' line to facilitate operation of the meters in series required a slightly-larger skid footprint. As designed, an NEL flow conditioner is installed, with the meter installed 10D downstream of the flow conditioner. The results from the Header Consortium indicates that a near optimum flow profile and acceptable swirl stability will exist in these conditions to ensure zero additional uncertainty due to installation effects (Ref 2).

1.5 FLOW TESTING

As part of the acceptance procedure for the meters and the skid design, a dry gas calibration was requested by the Department of Trade and Industry, Oil and Gas Office. This was carried out at the British Gas Bishop Auckland site against a master turbine meter in June 1995, and the results are presented here.

1.0 DAWN DEVELOPMENT

1.5 FLOW TESTING (CONTINUED)

The skid was flowed at four flows (10%, 25%, 50% and 100% of full scale) for the following combinations :-

- Flow through Meter 1.
- Flow through Meter 2.
- Flow through Meters 1 and 2 in parallel.
- Flow through Meters 1 and 2 in series.
- Flow through Meter 2, with its conditioner removed.
- Flow through Meters 1 and 2 in series with conditioner (#2) removed.
- Flow through Meters 1 and 2 at a reduced pressure of 38 bar.

See Figure 4.

Test Pressure : Maximum available on site : nominally 58 bar gauge (840 psig).
Test Temperature : Ambient : nominally 5 to 10°C.
Test Gas : Natural Gas : nominally 88% Methane.

Test Procedure : The metering skid was installed downstream of the site reference turbine meters. British Gas provided the secondary instrumentation to measure pressure and temperature at the ultrasonic skid and pressure, temperature and frequency output at the reference turbine meters.
The test line was pressurised to the maximum pressure available. The site flow control valve position was adjusted to produce the minimum flow required, 10% of 21 meters per second. When conditions steadied, six test points were collected.
Each comprised :-

1. Five sets of readings of all pressures and temperatures.
2. A one hundred second count of reference turbine meter output.

Item 1. above was collected for use with data averaged during Item 2.
The above procedure was repeated for 3 other flows up to the maximum velocity of 21 metres per second.

Calculations : The data from the reference turbine was converted, using the analysis of gas samples taken during the test, into a volume flow rate through the system. This together with the pressure and temperature at the turbine meter was corrected for the conditions prevailing at the ultrasonic skid.

The test installation allowed the meters to be calibrated independently, to test the efficiency of the header flow conditioner system in the parallel mode and provide a base line for the series tests for the meter to be used to track each other once the skid is placed into operation.

1.0 DAWN DEVELOPMENT

1.5 FLOW TESTING (CONTINUED)

It was anticipated that the tests with the meters in parallel and series operations with and without one conditioner will provide valuable data in respect of the validity of using flow conditioners in high pressure gas flow.

1.5.1 Test Result Traceability and Uncertainty

The flow meters are traceable to a Dutch standard (NMI) via a 4" Instromet turbine meter. The reference volumetric flows have an uncertainty of ±0.29%. The pressures are traceable to National standards via the dead weight tester used to calibrate the pressure transmitters. The uncertainty on pressure measurement was ±0.1%.
The differential pressure measured across the turbine meters and the skid discharge is traceable to National standards via the dead weight tester used to calibrate the DP transducer. The uncertainty on differential pressure measurement was ±0.25%.
The temperature circuit was calibrated using a traceable decade resistance box. The resistance probes had been individually calibrated. This produced an uncertainty of ±0.1% on temperature.

The overall Test Centre uncertainty for flow rate measurement is stated as ±0.4%.

1.5.2 Test Set Up

The test set up is shown in the schematic on Figure 3. The various flow configuration through the skid are shown on Figure 4. Due to constraints at the site and the physical size of the ultrasonic skid it was impossible to locate the skid close to the reference meters, and the need to use both an 8" and 12" reference meter to cover the total flow range, made it difficult to move these next to the skid. Furthermore the skid was mounted in a 24" line. These problems resulted in a large volume being present between the skid and the reference turbine meters. The volume was measured as 61 cubic metres which when compared to the 100 second calibration volumes was large. At 10% flow rate, the volume measured was $4m^3$ and at 100%, $40m^3$. In conditions of stable pressure and temperature this volume has no effect on the uncertainty of the experiment. However any change in these variables during each 100 second test point represented a net increase or decrease in density in the volume between the meters and this may have introduced a difference between the reference and test flows. Where applicable, these are represented by an estimated range of 'line pack errors' on the relevant figures and were provided by Bishop Auckland.

2.0 TEST RESULTS

2.1 INTRODUCTION AND TEST PROCEDURE

Flow Testing - what is it and why do we do it?

Flow testing is often purchased just as if we were buying widgits. Experience has shown that we rarely specify the performance envelope or all the details we want to see - or for that matter the installation under which the unit will be tested. We neither ask for (nor receive) details on the test site operations / areas which might affect the tests - and in some cases this can affect both the stability of the results and the time taken.

With respect to our testing at Bishop Auckland, we had stated the tests we wanted to carry out and been given a (fixed) price for a time slot. We had not agreed an installation location, reference meter location or discussed plant stability - this resulted in the situation described in 1.5.2. In retrospect, we should have located a single 8" meter just upstream of our skid and accepted the flow rate limitation - which would have limited the flow rate through one test point only - the 100% flow through two meters in parallel.

Another operational aspect to affect us, was British Gas pigging supply lines around Bishop Auckland. This meant for some days a loss of gas flow. Blending of gas supplies is thought to have ocurred to control calorific value resulting in changes in gas composition between the commencement and finalisation of the flow tests.

One aspect of the flow testing which surprised us all was the stability of some of the flow tests. Certain aspects were not as good as we had perceived, but that begs the question - is our perception that good?

2.2 FLOW ERROR RESULTS

i. Figure 5 compares the performance of Meter 1 and Meter 2 when being flowed independently with flow conditioners.
Meter 2 exhibits a 'dogleg' error vs flow rate. The error reported is in a band of -0.4% to +0.5% except at 10% flow. In general this meter lies within the claimed range for uncertainty.
Meter 1 exhibits a range of errors between +0.7% to -1.2% and if the span were adjusted would be within the claimed range of uncertainty.

ii. Figure 6 demonstrates the performance of the meter skid with both meters operating in parallel. What is not shown on this figure is the imbalance in flow through the two meters, which is less than 1%.
It could be argued that the very small imbalance is due to the dominant pressure

loss presented by the conditioners.
The error / flow rate curve is extremely flat and well within the errors claimed for the meters, and bodes well for the high rate (high value) flow metering when placed in operation.

iii. Figure 7 and 8 indicates the discrepancy of the meters when operated in series. Two sets of results are shown - Meter 1 and Meter 2 with conditioners (Figure 7) and Meter 1 with and Meter 2 without conditioners (Figure 8).
It should be noted that when conditioners are installed in both the meters in series, there was a high differential pressure across the skid and a pressure correction has been made for Meter 1, the upstream meter. At full flow the ΔP through both meters with conditioners was 21 psig. When one meter is operated on its own, with a flow conditioner the ΔP was approximately 9 - 10 psig. As a result, when in series with conditioners at full flow, there was a base line error for Meter 1 when compared with Meter 2.
This was estimated as :

$$\frac{10}{840} \times 100\% \quad = 1.2\%$$

and at half flow rate, it is assumed to be 1.2% x 0.25 = 0.3%. Errors were ignored below half flow rate.

Figure 7 indicates that both meters are within its claimed range of uncertainty, Meter 2 being in the range ±0.5% and approximately 0.5% above Meter 1.

Figure 8 indicates that Meter 1 (with a flow conditioner) and Meter 2 (without

a

flow conditioner have at the higher flow rates a similar performance.

iv. Figure 9 is a continuation of the Figure 7 data and compares Meter 2 installation with and without a flow conditioner. This demonstrates a clear half percent shift in metering error in the two installations. It is of interest that the 'dog' leg on this meter is present in both installations, and that the meter with the most acceptable error curve is the one tested with the conditioner.
This error shift corresponds to the work presented by the Installation Consortia (Ref 2), where the additional uncertainty recommended for a 6" meter with a 180° bend 10D upstream of the meter is ±0.5%.

v. Figure 10 provides an insight into the individual meters with flow conditioners operating a the lower operating pressure (of 38 bar). Both meters perform within their claimed performance envelope, however the need to pre-heat and reduce pressure in the system has added to the line pack and pressure control problem thus increasing error scatter.
This figure is the result of at least 4 different tests and this may be the reason for the apparent drift between results, but there does appear to be some repeatability.

2.3 VELOCITY OF SOUND

Velocity of sound (VOS) which is a property of a gas at a given pressure and temperature is an excellent "diagnostic tool" in reviewing data from the meter. It uses the same geometry and time measurements that are required to determine line / chord velocity.

Measurements of velocity of sound of the flowing gas are made at each chord. It was observed that the interchord VOS agreement was good (ie better than 1 in 400, ie <0.25%). This was to be expected - a six inch meter is small with few dead areas for temperature gradients to form. The fact that velocity of sound errors were small confirms that the individual chord geometry and timing is good.

In series and in parallel meter installations had good correlations for VOS. This was expected as the same gas passes through both meters.

However, it was noted that there were changes in VOS between the beginning and the end of the tests. A review of the gas sample component analysis after the test showed that there was a clear shift in gas analysis from a relatively 'lean' gas to a more 'richer' mixture. See Table 1 below.

Component	Sample Number 492	Sample Number 495
Methane	91.29	86.946
Ethane	4.66	6.989
Propane	1.37	2.430
N-Butane	0.26	0.450
Iso Butane	0.12	0.207
Pentanes	0.07	0.146
N-Hexane	0.02	0.063
Carbon Dioxide	1.39	2.113
Nitrogen	0.80	0.654
Mol Wt.	17.78	18.77

Table 1

Figure 11 indicates the range of VOS seen throughout the test and compares the measurements made between the meters. The agreement in the VOS corresponds to the agreement in calibration between the meters. A 1% error in velocity corresponds to 0.5% error in VOS. Work after the tests revealed that the major change in VOS is due to composition (15 m/sec). Changes in process temperature resulted in a change of around 4m/sec. The VOS ranged between 376 and 392 m/sec..

2.4 FLOW PROFILES

The ultrasonic meter has the ability to provide a large range of data. Amongst this data is the flowing velocity through each of the four measuring chords and the weighted average of the 4 chords. This data can be used to observe elements of the flow profile effects caused by the pipe work through the meter in the following installations:-

- Meter 1 and Meter 2 (with flow conditioners)
- Meter 2, with and without flow conditioners

and - Meter 2 with and without the flow conditioner in series with Meter 1.

However, it should be noted that the flow profiles presented show only 4 points for each profile and are non dimensional average velocity profiles (not centre line velocity profiles) and possibly do not provide as much data on the performance of the flow conditioner (swirl etc) as is necessary to give conclusive data on its performance.

The Pipe Reynolds numbers for full and half rate flow are 9.0×10^6 and 4.4×10^6 respectively.

i. Figure 12, comparing Meter 1 and Meter 2, with flow conditioners indicates that the flow profile for Meter 1 is somewhat more symmetrical than that observed in Meter 2. For all tests, Meter 1 always had a flow conditioner, and whilst not shown elsewhere was always symmetrical and very close to a fully developed flow profile.

ii. Figure 13 compares Meter 2 with and without the flow conditioners. The figure indicates that the flow profile is asymmetrical and marginally better (more symmetrical) without the conditioner.

iii. Figure 14 compares Meter 2 with and without the conditioner in series with Meter 1. We considered that this was a severe flow with 2 radiused bends and two sharp bends through piping tee's within a confined space but a subsequent review of this data - indicates that the configuration may not be as severe as first thought. It is however probably more akin to a 180° bend upstream of the meter. It would appear from this data that the flow conditioner in this installation provides no advantage which is not backed up by the data from Figure 9 which compares the 0.5% difference between installations with and without the flow conditioner. This 0.5% shift corresponds to the data provided form the Installation Consortia (Ref 2).

2.5 STANDARD DEVIATION OF DELTA TIME

The delta time (DLTT) is the difference in the time for the ultrasound to travel from the downstream transducer of a chord pair to the upstream (T1) and the upstream transducer to the downstream transducer (T2), delta rime = (T1 - T2).

Typically a batch of 20 times are used to calculate velocity and provide statistical analysis. These batches are analysed and the standard deviation of the delta time is

calculated. Large shifts of standard deviation of delta time can be caused by swirl, turbulence and liquids or solids in the flow. In essence it is a measure of the disturbed nature of the flow. Figure 15 plots the standard deviation against flow for three installations.

- Meter 2 alone, no flow conditioner.
- Meter 2 in series with a flow conditioner.
- Meter 2 in series with no flow conditioner.

It was considered that these three installations would provide the best "installation effect" comparison. The first two installations had almost identical standard deviations. This indicates that the flow state in a normal flow route without a conditioner is very similar to that when in the complex series flow mode but treated with a flow conditioner.

The last installation, series flow, no conditioner has a distinct shift (upwards) in standard deviation. When looked at on its own, this may be considered significant. However, experience from other installations where two out of plane elbows have been installed with a half plate orifice upstream of the USM standard deviation shifts in the order of 5 or 6 times the base value have been experienced. Compared with this prior installation knowledge it could be said that the test flow conditions were good.

2.6 PLANT STABILITY

During the tests, it appeared that the flow facility had a problem with plant stability at high flow rates.
Measurements were taken by the facility over 100 second windows every 10 seconds, and an average flow over the 100 seconds was computed and compared with the USM. These flow tests were repeated up to 5 times.Our concern was that at each repeat the average flow would change and in most cases it would drop continously
Stability and line pack were also judged by these 10 second measurements..
Figure 16 demonstrates the drop in flow (at high flow rates) through the reference meter and the response from the USM in a variety of installations.
The plots of pressure and temperature are shown in Figure 16. They should be read as the time base starting at the right hand side (near flow rate at 1449) and trend as a drop in pressure and temperature over the test. Whilst the test facility recorded these changes over 10 second intervals we were left with an uneasy feeling about the repeat tests.

We perceived this apparent lack of stability as another potential source of errors - but are our perceptions correct?

3.0 DISCUSSION

Earlier discussions have commented on the Bishop Auckland Test Facility uncertainty. The overall uncertainty claimed is ±0.4%. The configuration utilised for testing was not ideal and this has been recognised . Notwithstanding the above, the results derived exhibit a high degree of repeatability which bodes well for confidence in the skid design and the meters.

It was surprising not to see greater differences in velocity profiles in the various installations. However, profile configurations are not merely a function of local velocity but of swirl also, and it is swirl which causes great interest, especially in orifice installations. The chord velocities as measured by the USM are functions of axial velocities and swirl (in a plus or minus sense), and represent a single line average value for each chord. As a result, we were probably expecting too much in this area. By observation of the standard deviation of DLTT we are able to comment on the installation (of Meter 2) with and without flow conditioners. We observed a discrepancy at high flow rates of standard deviation in the order of 10%. Knowing that a really severe flow disturbance will cause this figure to change by a factor of 6 or so, these observations are probably understandable.

The error, flow profile and standard deviation all indicate that the series pipework with no flow conditioner is a qiute mild flow disturbance.This configuration is more like a 180 degree bend rather than two 90 degree offset bends, as in fact the bends are only 20 degrees offset and are not close coupled. The error shift of 0.5% agrees with the Ultraflow work for a 180 degree bend 10D upstream of the meter.
Meter 2 with no flow conditioner has a more symmetric flow profile, approaching that of Meter 1 with a flow conditioner and the error curves are also similar.

At reduced flow rates, the line packing errors, meter geometry and meter timing errors all increase and leads to a wider uncertainty band, and this was clearly demonstrated.

4.0 CONCLUSIONS

- Meter Skid

  - The tests clearly demonstrated that high performance compact meter skids are now achievable.

- Meter Error

  - Under all conditions, the meters were within the claimed ±1% of a factory dry calibrated meter.

  - In the parallel flow mode, the 'meter' skid uncertainty is better than ±0.5% - a real confidence boost for high flow (high risk) production.

- Velocity of Sound

  - The agreement of velocity of sound between interchord and inter-meter measuremnts corresponds to the meter errors. Interchord VOS agrees to 0.1% and inter-meter VOS to 0.5% and is consistent with the meter error above.

- Flow Profiles and Flow Conditioners

  - The inability to measure flow profile in the classical manner left the question of flow improvement unanswered.

  - Meter 2, with a flow conditioner was more accurate with respect to the reference meter.

  - Meter 2 without a flow conditioner and Meter 1 (with a flow conditioner) had a similar performance.

  - The installation of the flow conditioner provided sufficient differential pressure to equalise flow around the skid in parallel mode operation.

- Standard Deviation

  - Standard deviation as a measure of disturbance showed that only small velocity profile effects occurred in the different skid arrangements.

ACKNOWLEDGEMENTS

1. The Wet Gas JIP (which consists of BP International, British Gas, Shell Expro, NAM, Phillips Petroleum, Amoco Europe, and Daniel Industries) sponsored the work on wet gas, and contributed to these dry gas calibrations and have generously allowed this publication. The DTI participated with the JIP and their input is gratefully acknowledged.

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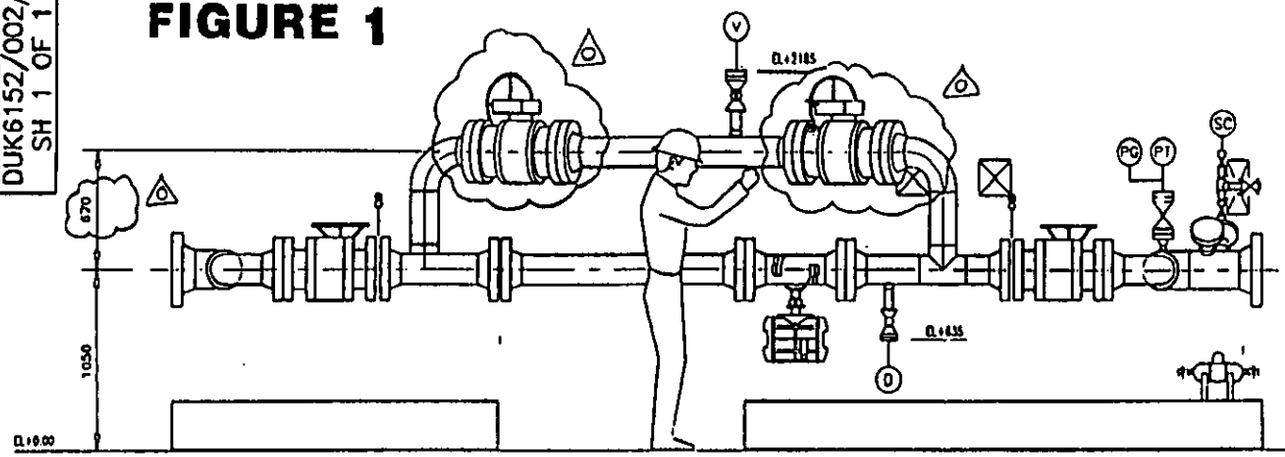
2. BLOEMENDALL, Van K., KAM, Van Der, P.M.A., Installation Effects on Multipath Ultrasonic Flow Meters : The Ultraflow Project. In Proc of North Sea Flow Measurement Workshop, Peebles, Scotland. National Engineering Laboratory, East Kilbride, Glasgow, Scotland, 1994.

3. READER-HARRIS, M.J., SATTARY, J.A. and WOODHEAD, E., The Use of Flow Conditioners to Improve Flow Measurement Accuracy Downstream of headers. In proc. of 3rd International Flow Symposium, San Antonio, Texas. Gas Research Institute, Chicago, 1995#

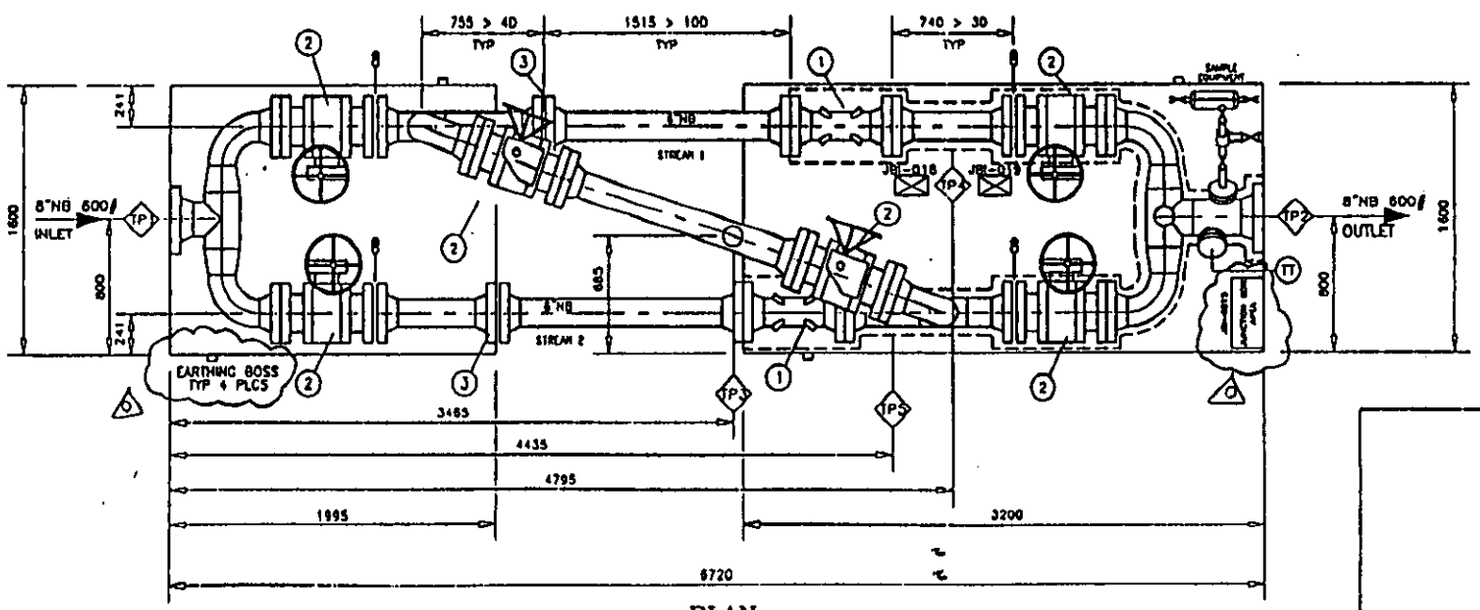
ISSUE 0

DRAWING NUMBER DUK6152/002/1 SH 1 OF 1

FIGURE 1



~ELEVATION~



~PLAN~

TERMINATION SCHEDULE

- TP1 8" 600# RF INLET
- TP2 8" 600# RF OUTLET
- TP3 2" 600# RF VENT
- TP4 1 1/2" 600# RF DRAIN (STREAM 1)
- TP5 1 1/2" 600# RF DRAIN (STREAM 2)

MAJOR ITEMS

1. 8" 600# WET GAS ULTRASONIC METER.(NOT INCLUDED)
2. 8" 600# FULL BORE BALL VALVE.(MANUALLY OPERATED)
3. FLOW STRAIGHTENER

LEGEND

- V VENT
- D DRAIN
- PT PRESSURE TRANSMITTER
- PC PRESSURE INDICATOR
- TT TEMPERATURE TRANSMITTER
- SC SAMPLE CONNECTION (MANUAL)
- ------ DENOTES INSULATION

00-001-001-B

PHILLIPS PETROLEUM COMPANY U.K. LIMITED

PROJECT: DAWN FIELD DEVELOPMENT

TITLE: OVERALL FIELD LAYOUT

ISS	DATE	CHANGE	CHKD	APPD	ISS	DATE	CHANGE	CHKD	APPD
A	7/3/95	FOR MANUFACTURE (EC/3028/95)	DB	SL					
	25.2.95	FOR APPROVAL	DB	SL					

ORIG SCALE 1:15 A1

DIMENSIONS IN mm

REF S.O.4212

DANIEL INDUSTRIES LIMITED

PHILLIPS DAWN PROJECT

DRAWN D.Fisher

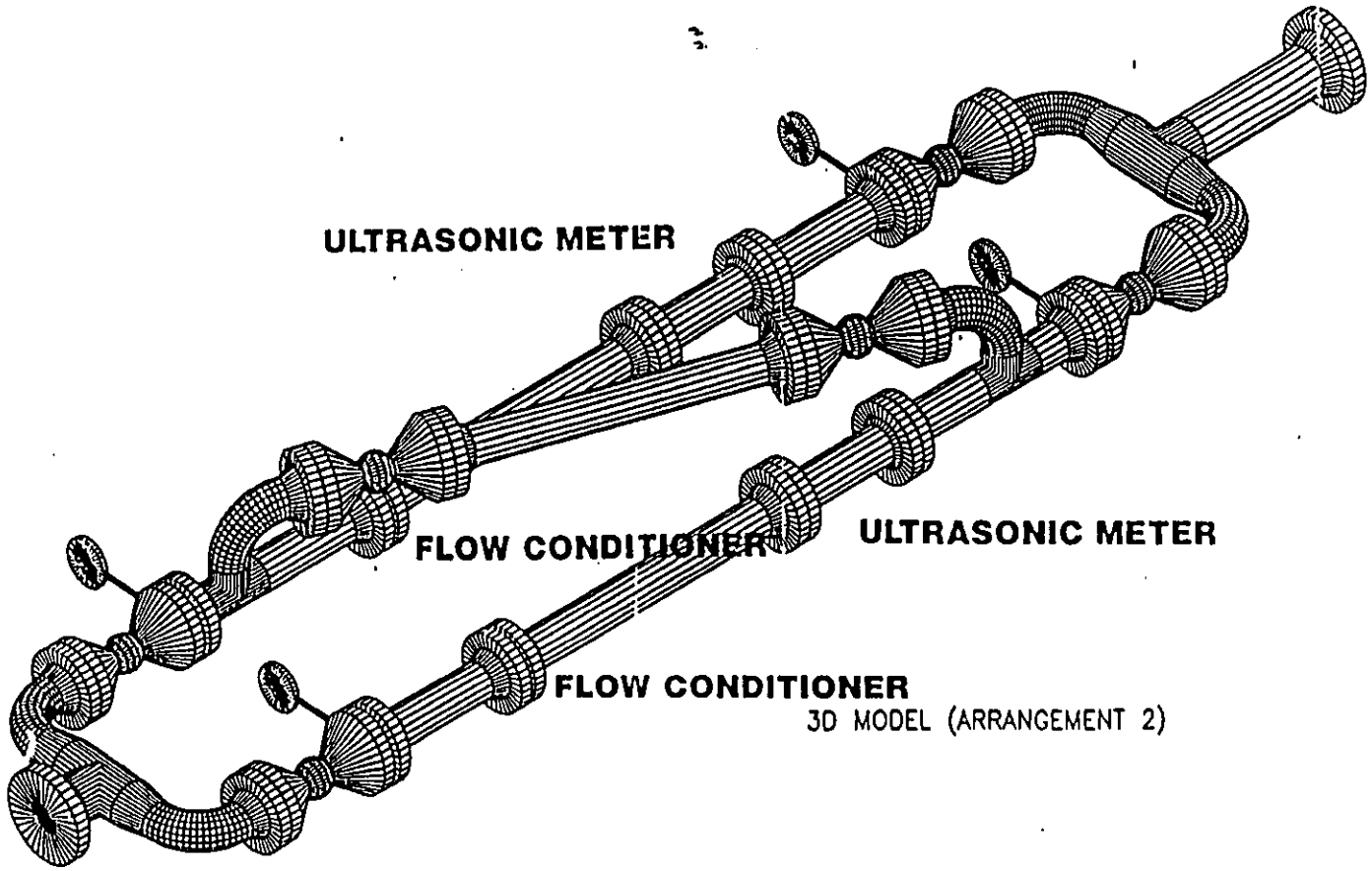
DRAWING NUMBER DUK6152/00[redacted]1 SH 1 OF 1

ISSUE 0

ISSUE A

DRAWING NUMBER DUK6152/005/1 SH 1 OF 1

FIGURE 2



3D MODEL (ARRANGEMENT 2)

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A	10.1.95	FOR TENDER							

ORIG SCALE 1:10 A1
DIMENSIONS IN mm
REF EC 0276

DANIEL INDUSTRIES LIMITED

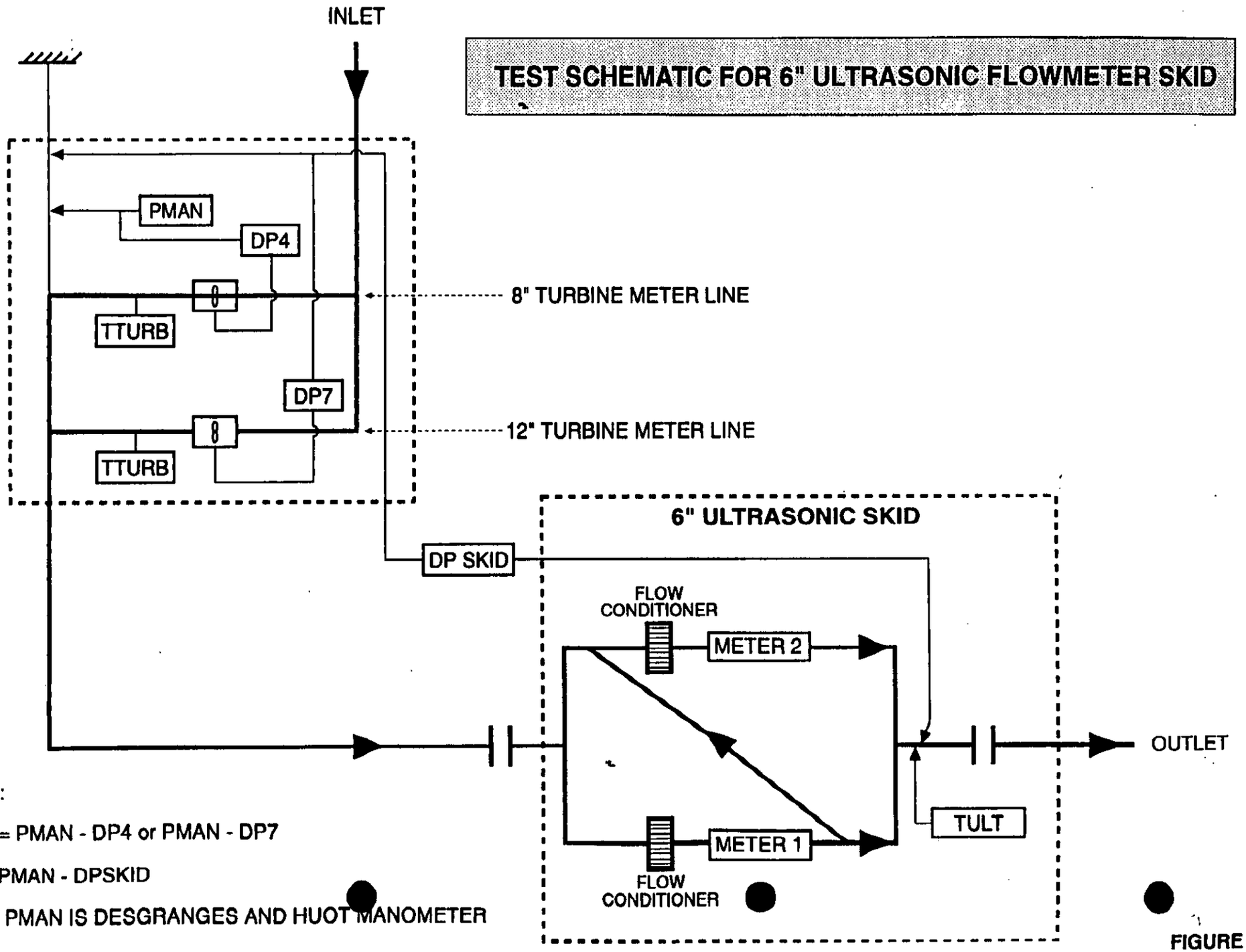
PHILLIPS
HEWETT/DAWN
DEVELOPMENT (ARRANGEMENT 2)

DRAWING NUMBER DUK6152/005/1 SH 1 OF 1

DRAWN AJF

ISSUE A

TEST SCHEMATIC FOR 6" ULTRASONIC FLOWMETER SKID



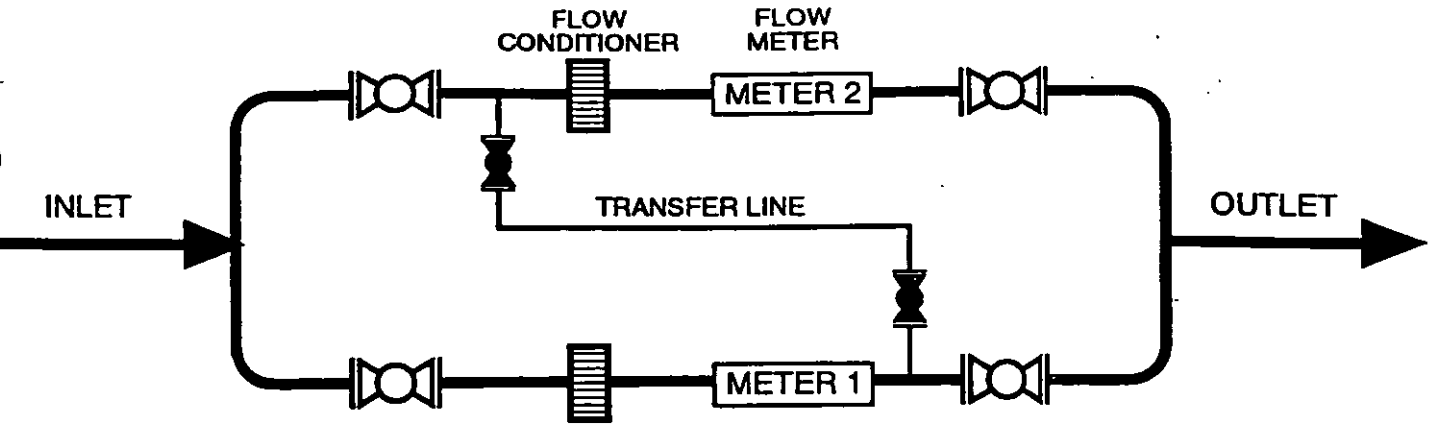
NOTES :

PTURB = PMAN - DP4 or PMAN - DP7

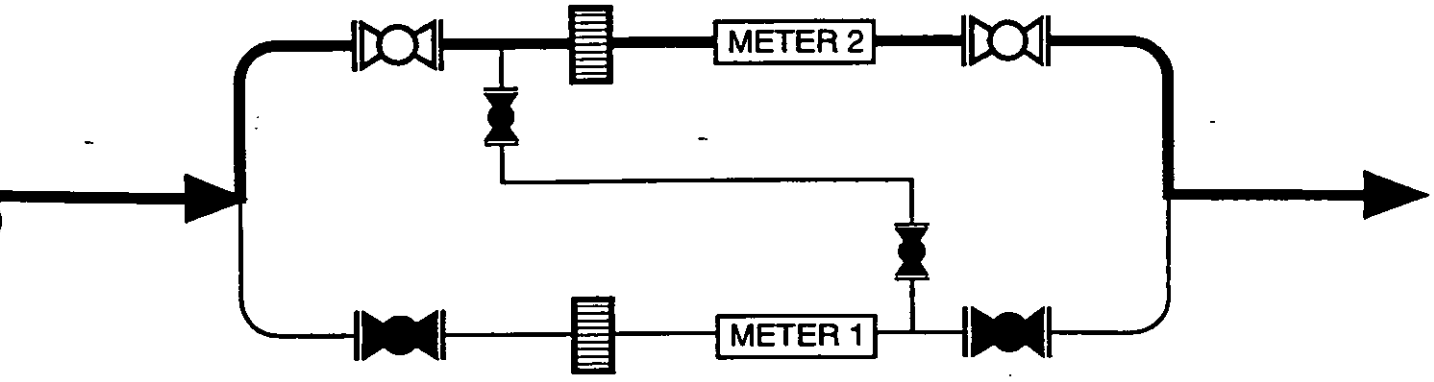
PULT = PMAN - DPSKID

WHERE PMAN IS DESGRANGES AND HUOT MANOMETER

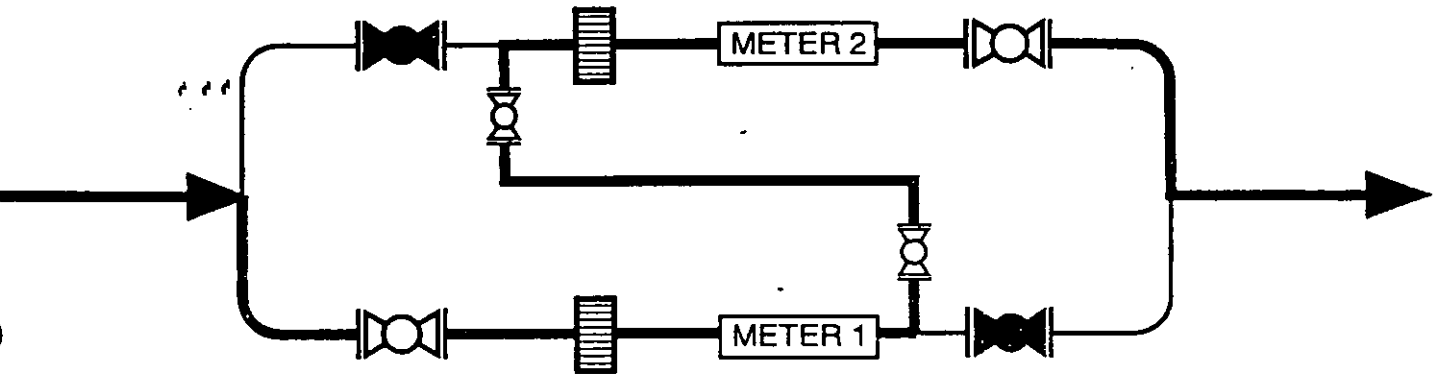
FIGURE 3.



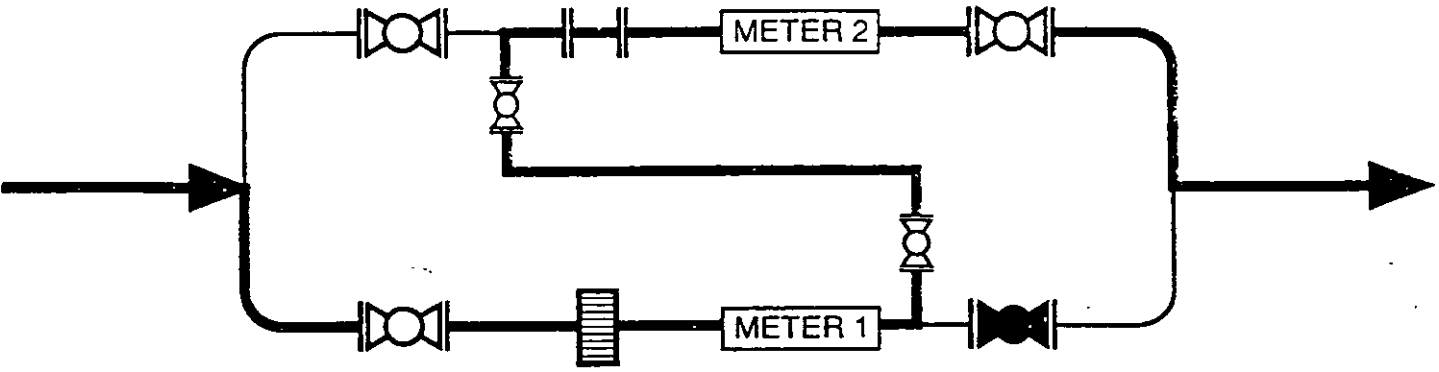
PARALLEL FLOW.



INDIVIDUAL FLOW.



SERIES FLOW, WITH CONDITIONER.

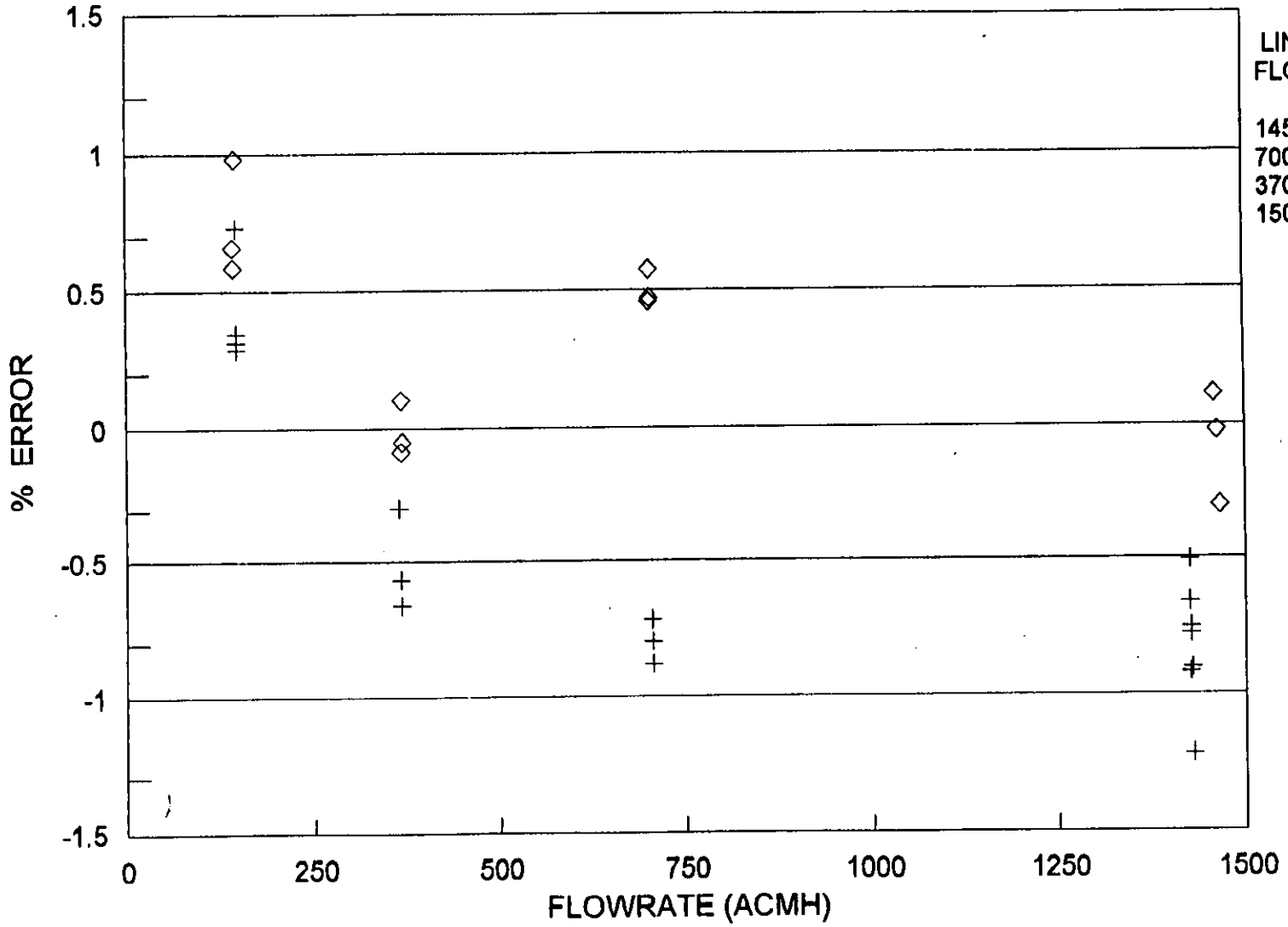


SERIES FLOW, WITHOUT CONDITIONER.

FIGURE 4. - FLOW SCHEMATIC PERMUTATIONS

METERS 1 & 2 COMPARED

INDEPENDENT INSTALLATIONS WITH CONDITIONERS



LINE PACK ERROR

FLOW	MTR 1	MTR 2
1450	0.042-0.05%	0.18-0.33%
700	0.09-0.2%	0.06-0.1%
370	0.017-0.9%	0.4-0.5%
150	0.26-0.47%	0.2-0.88%

◇ METER No 2

+ METER No 1

FIGURE 5

METERS IN PARALLEL

ERROR % Vs FLOWRATE(ACMH)

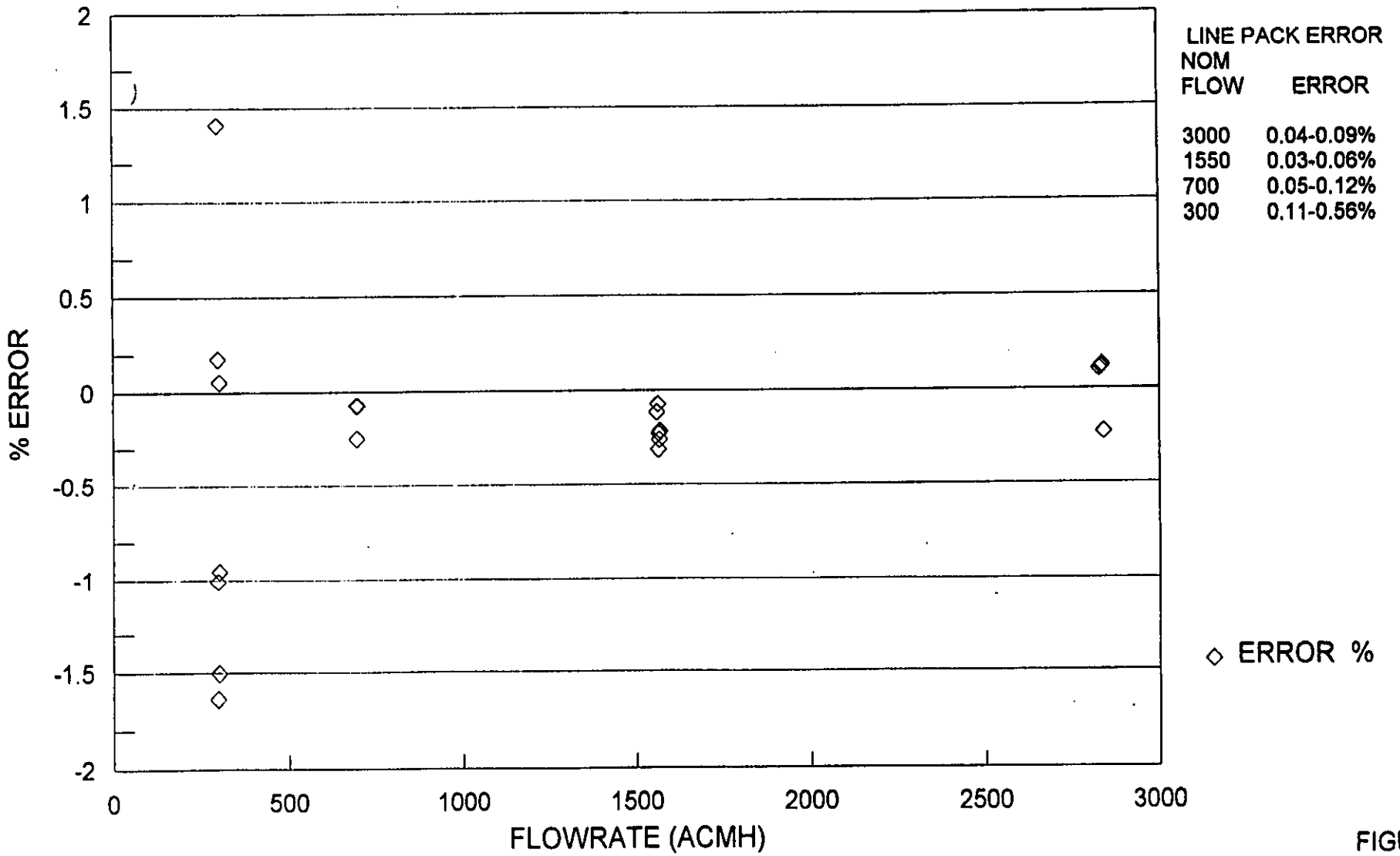
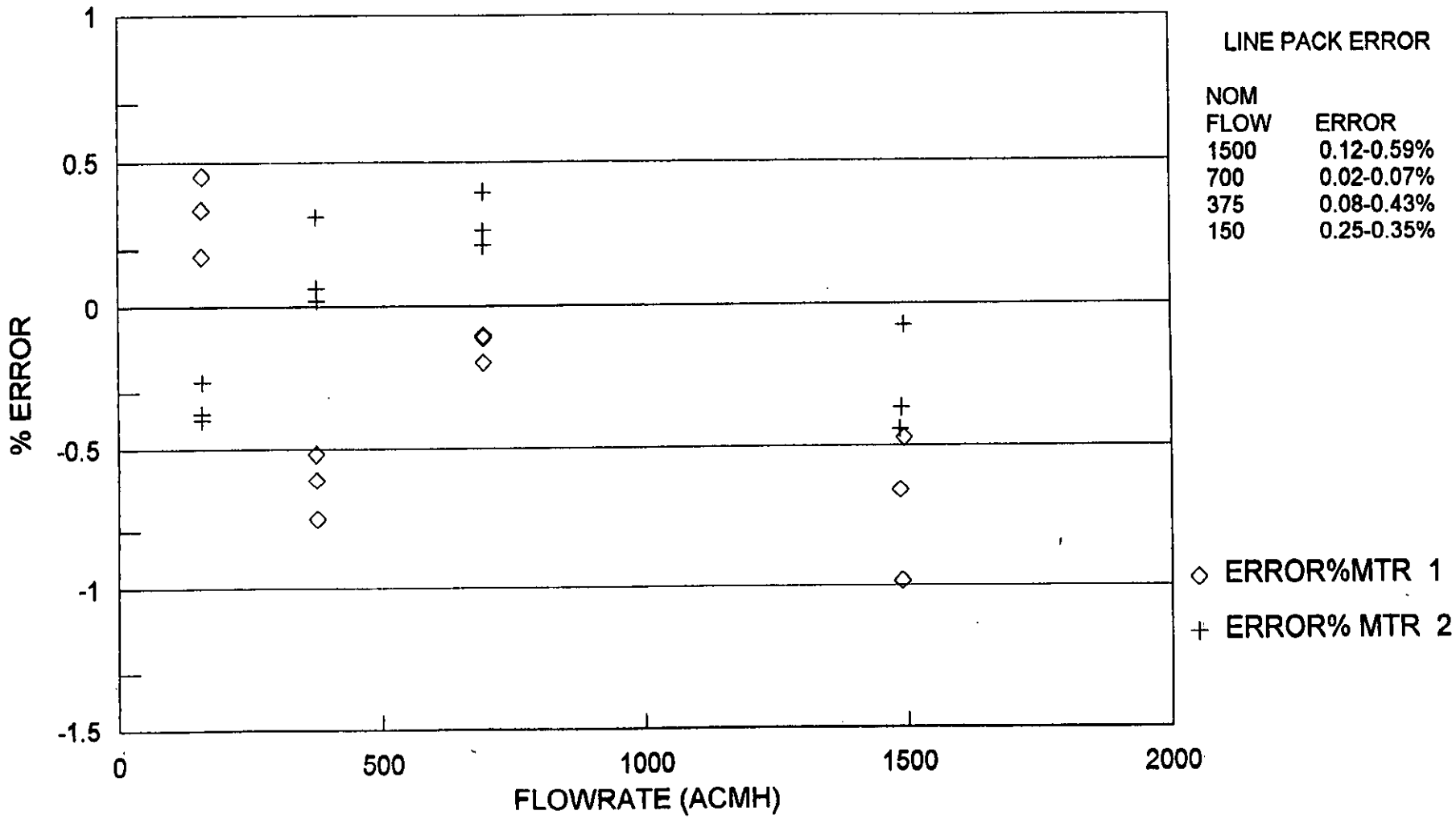


FIGURE 6

METERS No 1 & 2 IN SERIES

C/W FLOW CONDITIONERS



PRESSURE CORRECTIONS MADE FOR HIGH AND MEDIAN FLOWS

FIGURE 7

METERS 1 & 2 IN SERIES

METER 2 WITHOUT FLOW CONDITIONER

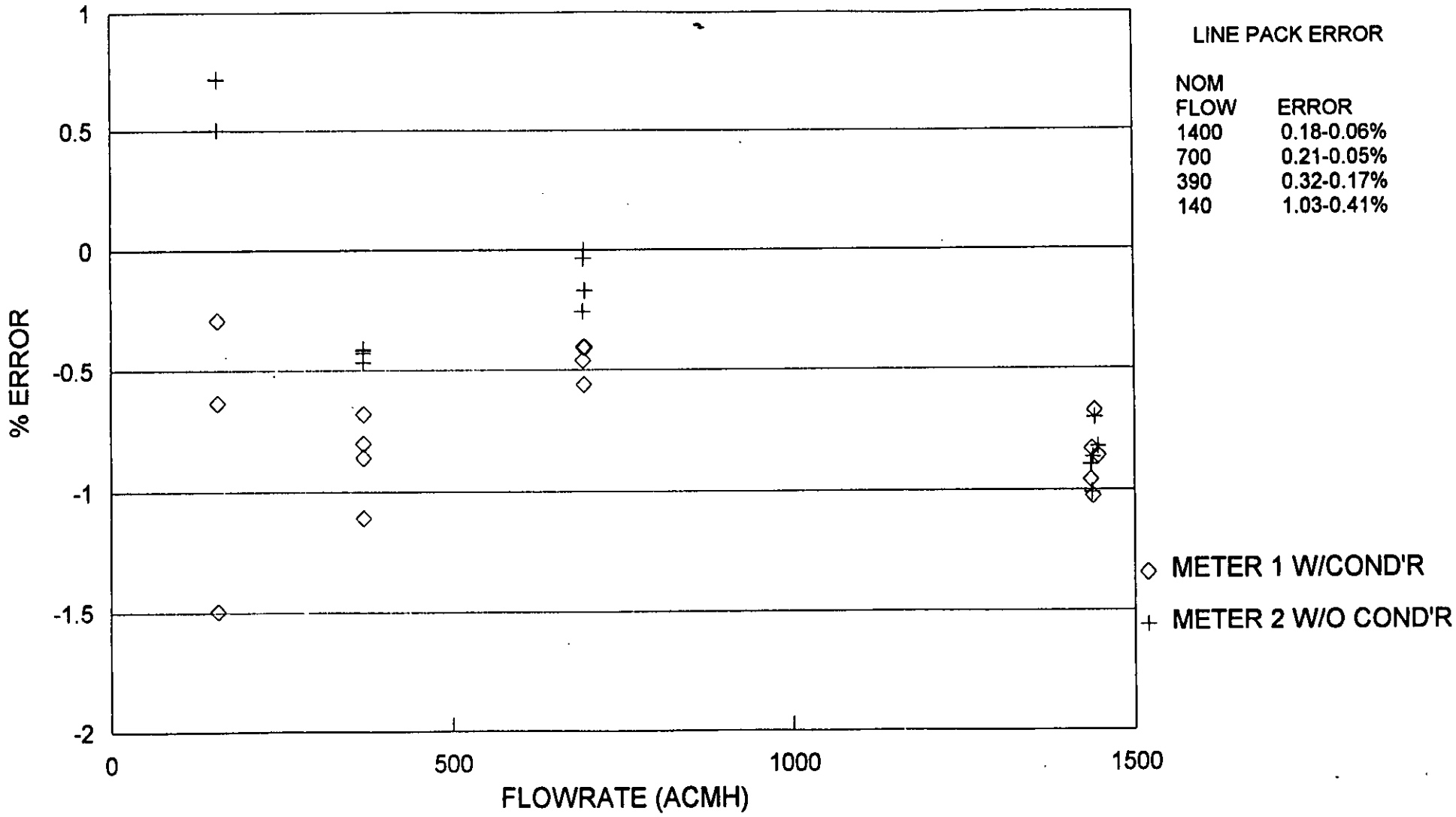


FIGURE 8

METER No 2

WITH AND WITHOUT FLOW CONDITIONER

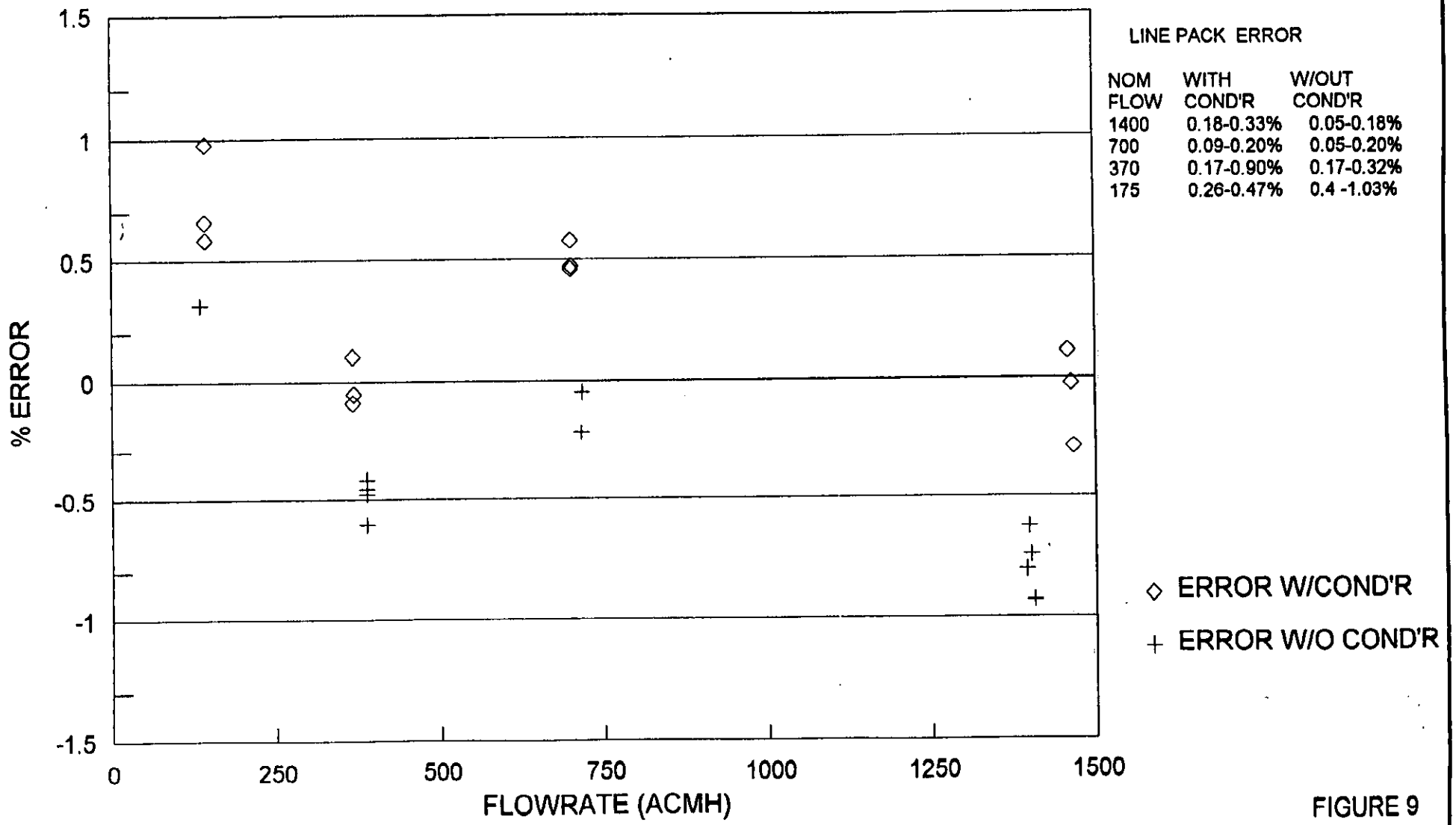
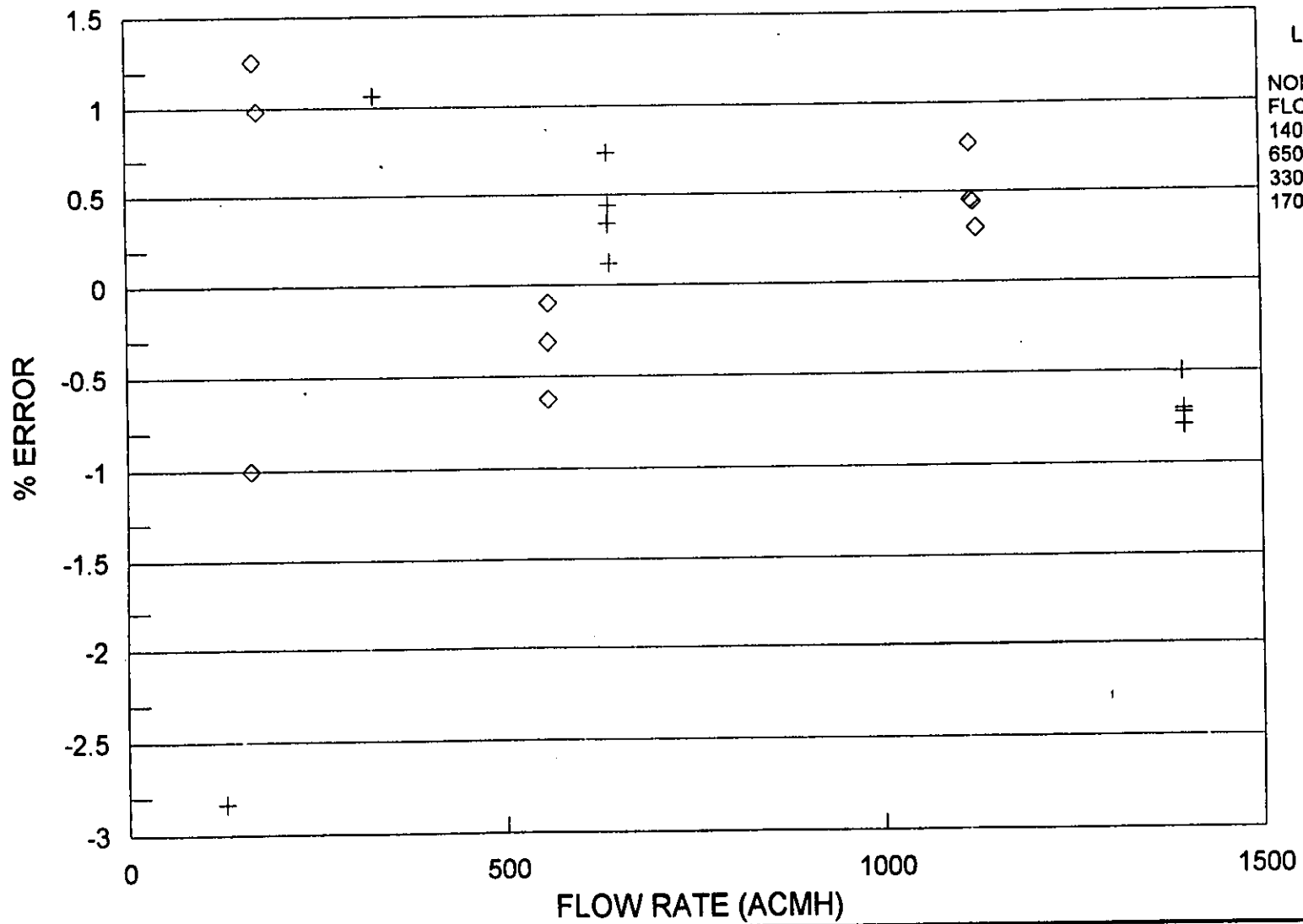


FIGURE 9

METERS 1 & 2

LOW PRESSURE FLOW (38Bar)



LINE PACK ERROR

NOM FLOW	MTR 1	MTR 2
1400	0.40-0.05%	0.58-0.22%
650	0.67-0.10%	0.65-0.10%
330	0.72-0.15%	0.85-0.35%
170	0.62-0.55%	1.29%

FIGURE 10

VELOCITY OF SOUND

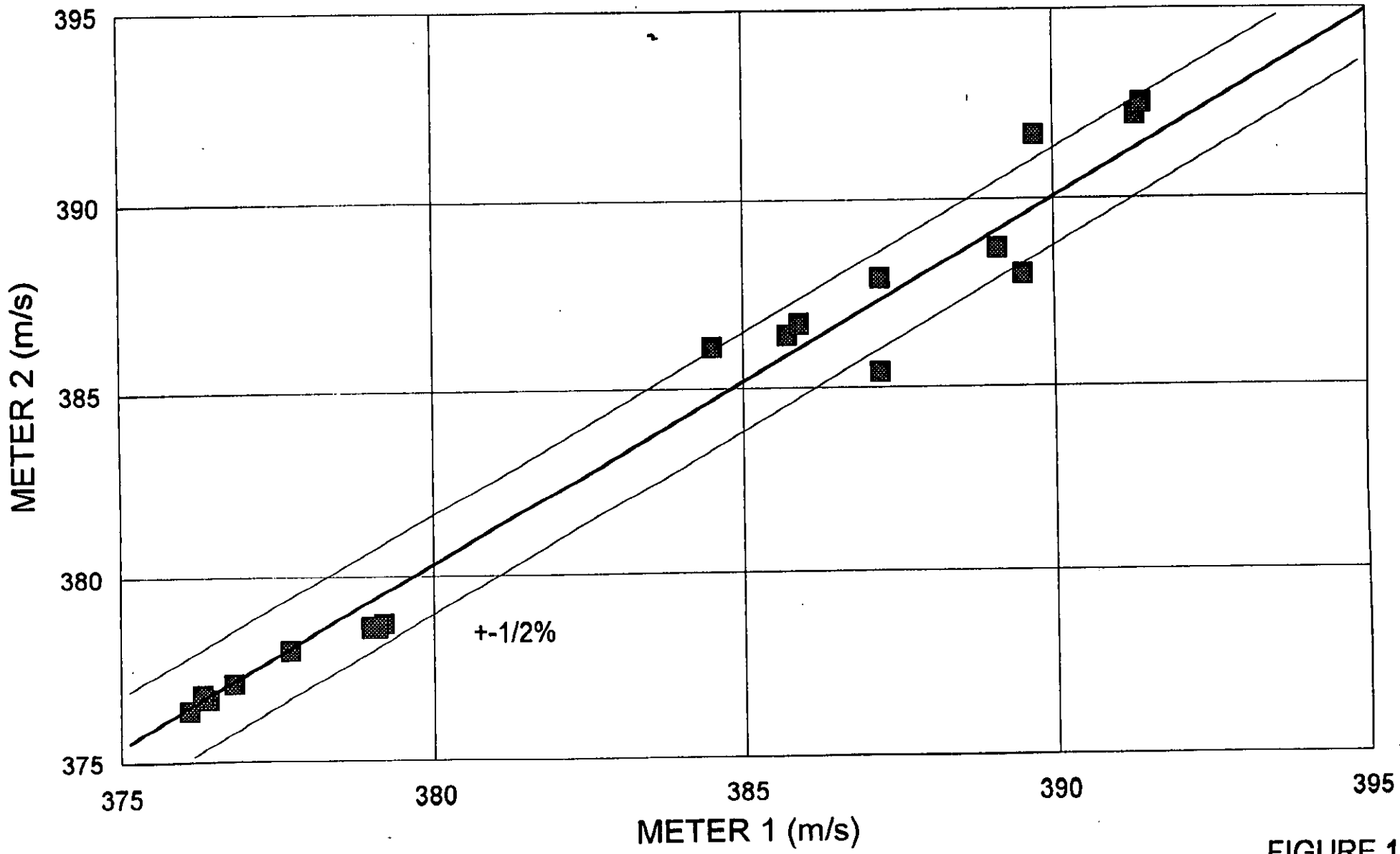


FIGURE 11

6" METER VELOCITY PROFILE

METERS #1 & 2 (WITH CONDITIONERS)

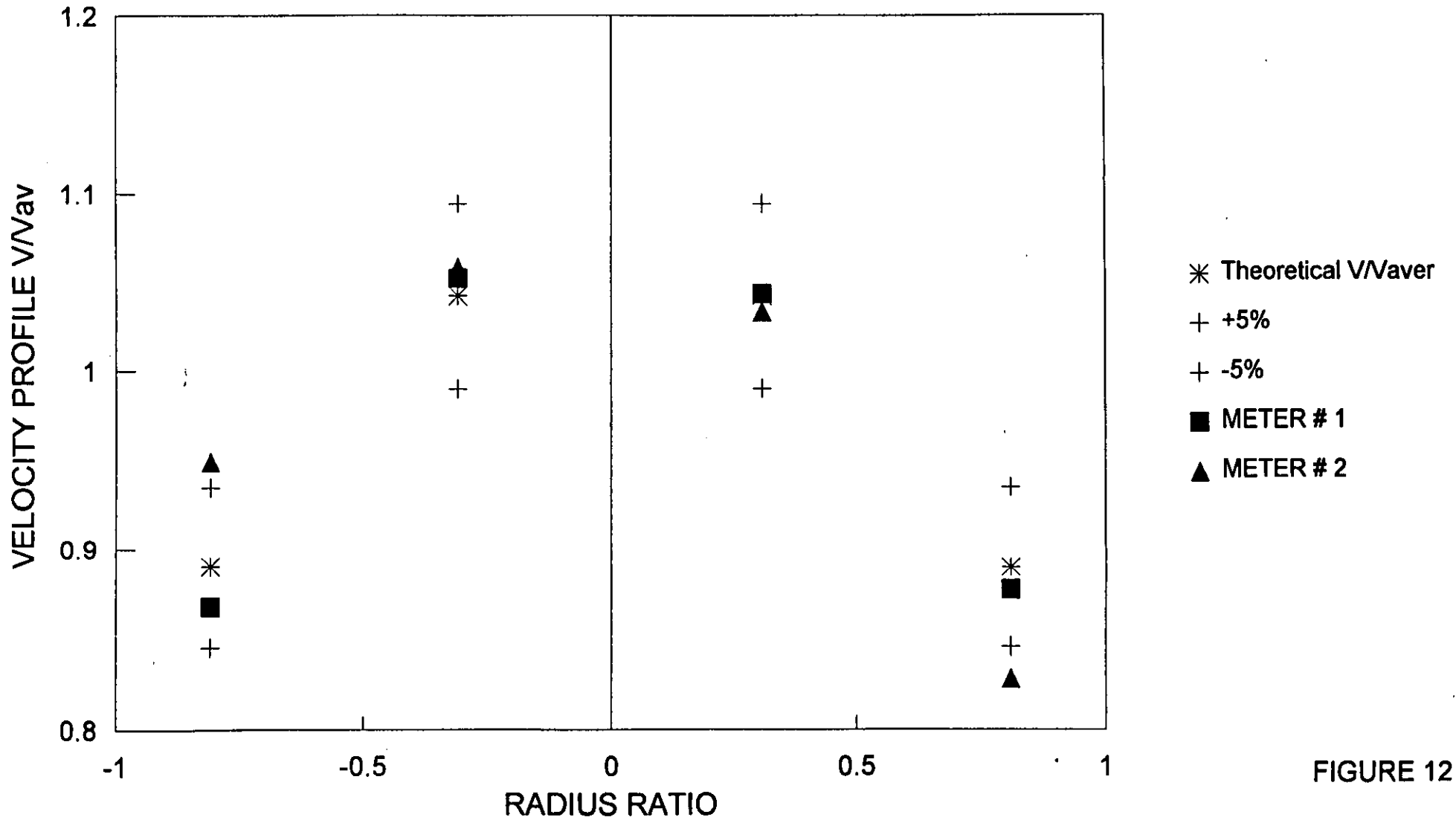


FIGURE 12

6" METER VELOCITY PROFILE

METER # 2 WITH & WITHOUT FLOW CONDITIONER

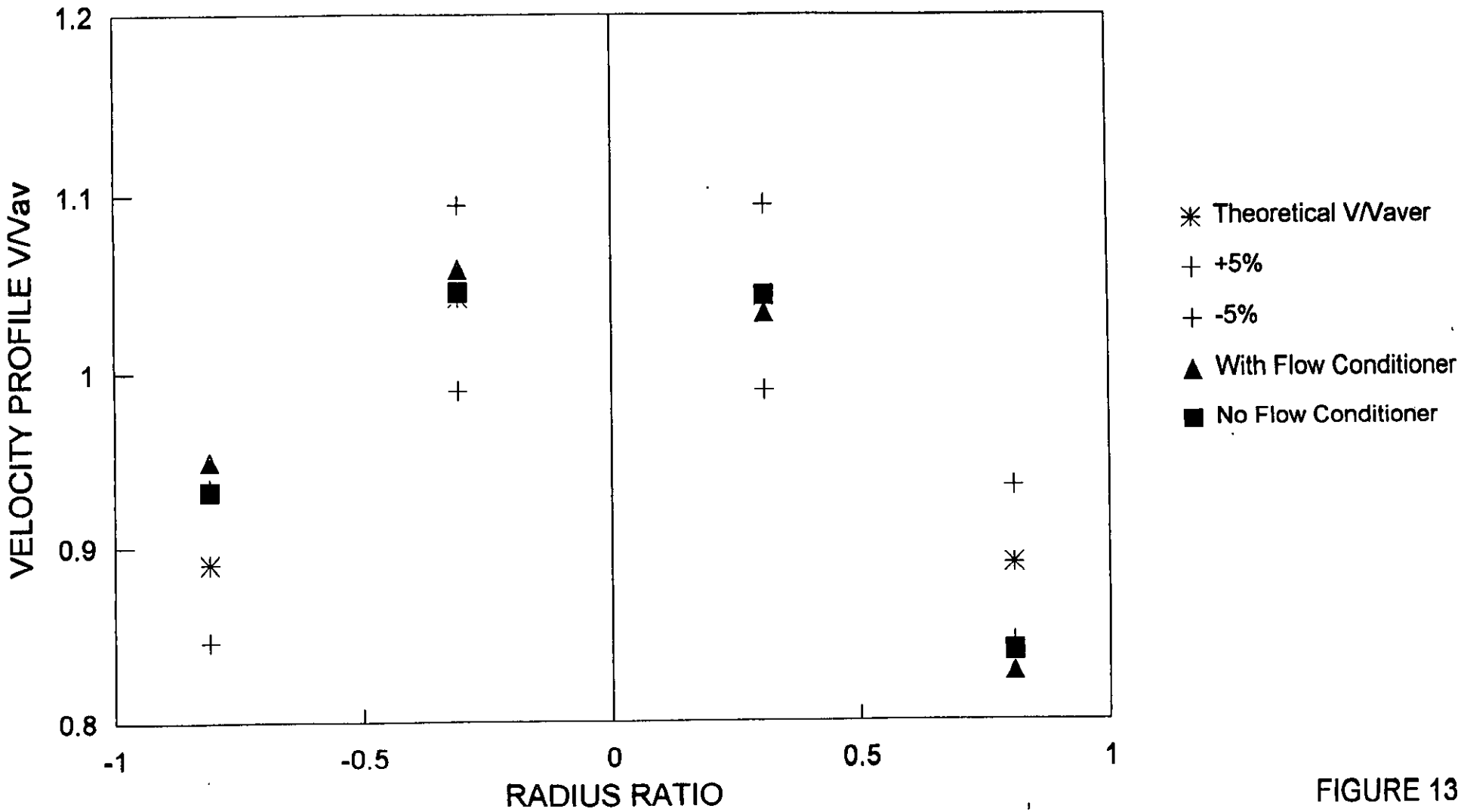


FIGURE 13

6" METER VELOCITY PROFILE

METER #2 IN SERIES WITH & WITHOUT CONDITIONER

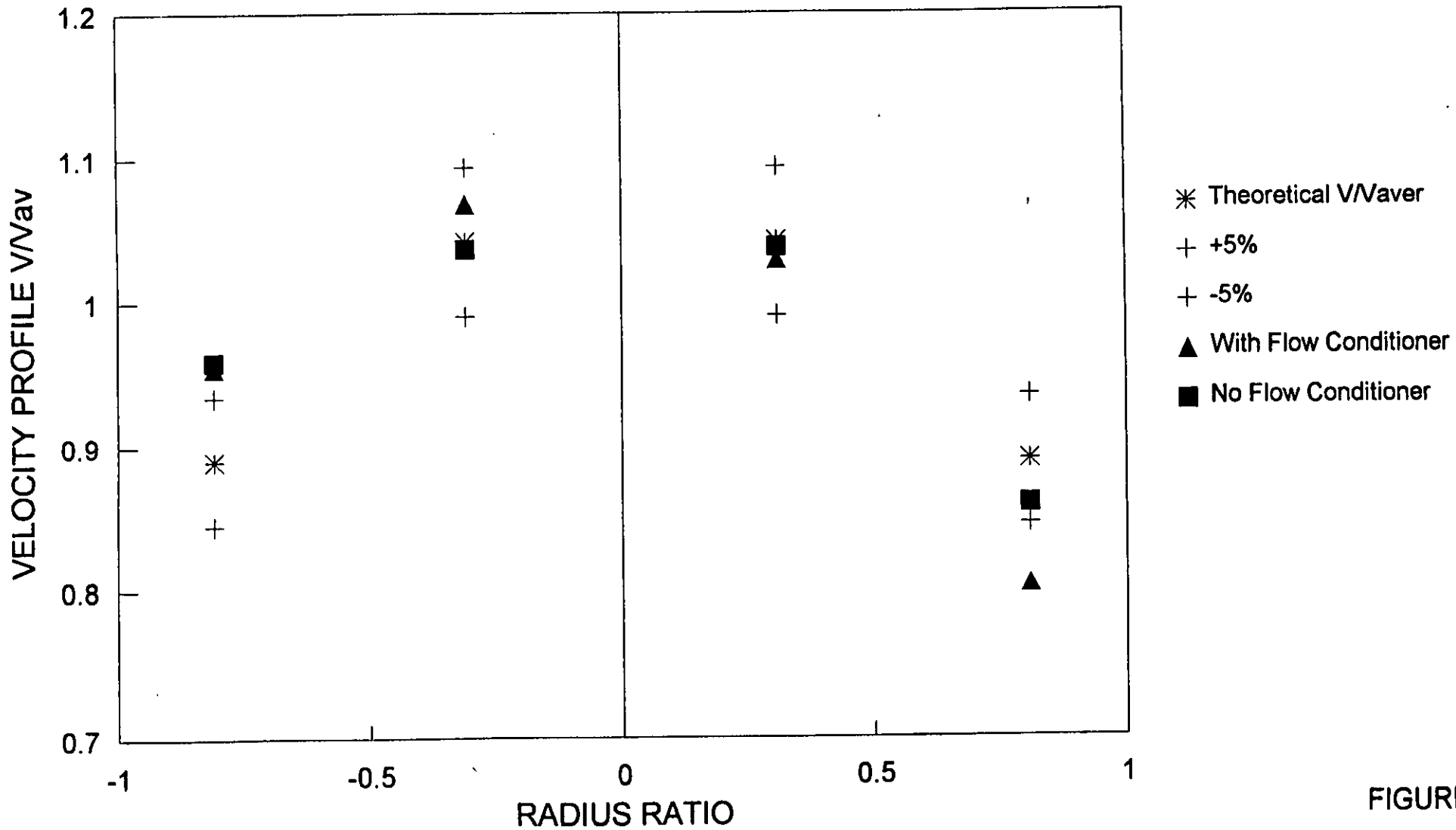
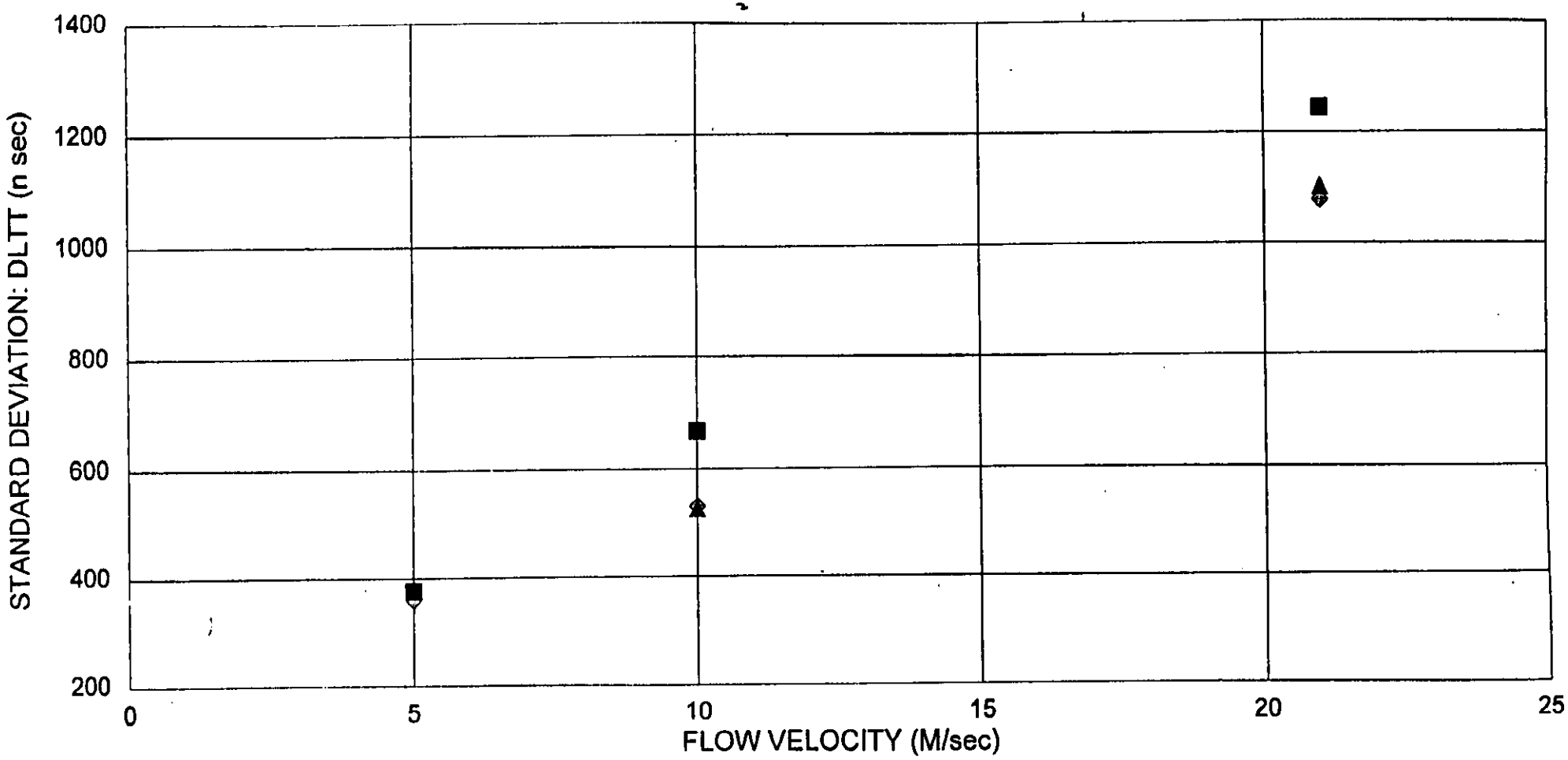


FIGURE 14

STANDARD DEVIATION (DLTT) Vs FLOW RATE

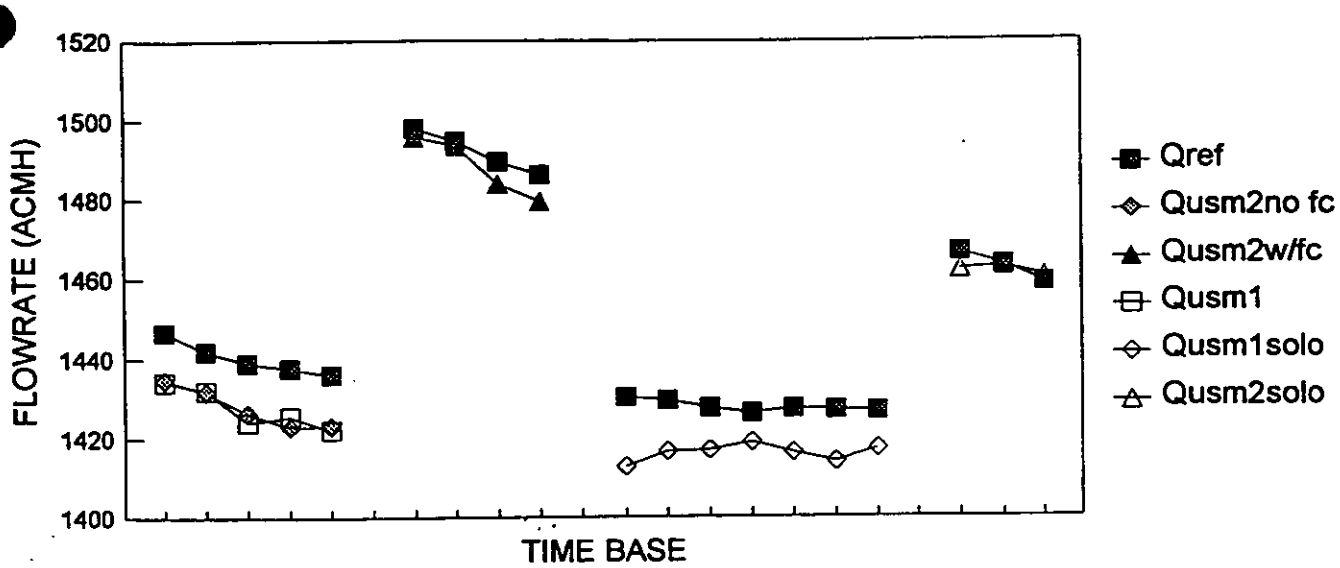
FOR DIFFERENT INSTALLATIONS



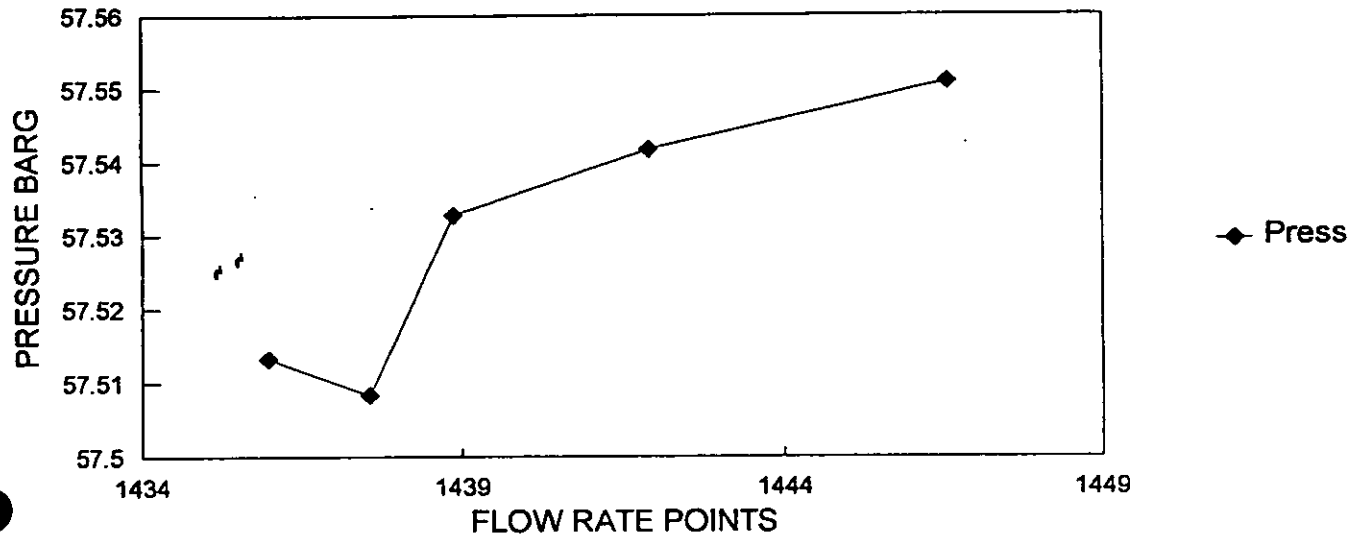
◇ METER 2 ALONE:NO FLOW CONDITIONER ▲ METER 2 IN SERIES WITH FLOW CONDITIONER ■ METER 2 IN SERIES : NO FLOW CONDITIONER

FIGURE 15

METER COMPARISON: Qref Vs Qusm



PRESSURE VARIATIONS



TEMPERATURE VARIATIONS

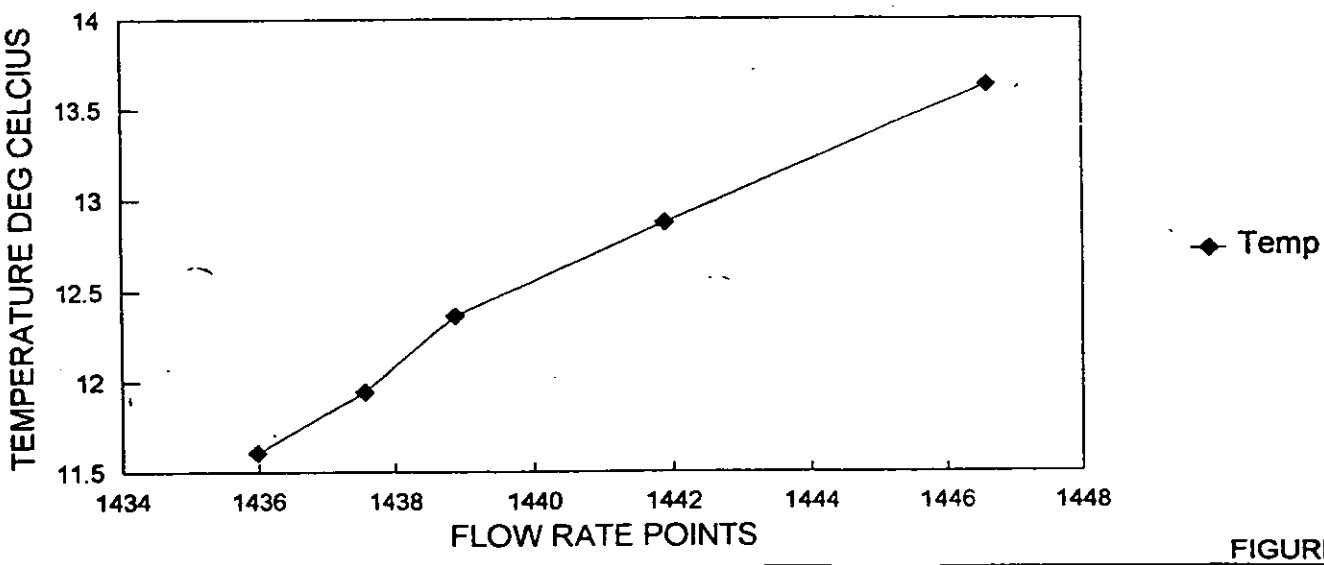


FIGURE 16

Main Index

North Sea FLOW Measurement Workshop 1995

Paper 16:

CORIOLIS FLOWMETERS FOR GAS MEASUREMENT

5·2

Authors:
Tim Patten and Gary Pawlas
Micro Motion Inc, USA

Organiser:
Norwegian Society of Chartered Engineers
Norwegian Society for Oil and Gas Measurement
Co-organiser:
National Engineering Laboratory, UK

GAS DENSITY MEASUREMENT

Since a Coriolis meter vibrates at a resonant frequency and the meter frequency changes when the fluid density changes, density can be measured as the meter frequency changes. Initial testing has indicated that with the current calibration method density accuracy is better than ±2 kg/m^3 over the entire tested flow range for each meter size. Micro Motion's current density calibration consists of correlating the density of ambient air to a tube frequency, and correlating the density of ambient water to a second tube frequency. The line resulting from these two points defines the relationship between frequency and density for all densities.

Micro Motion recently worked very closely with a customer to solve a difficult measurement problem in a process gas application. Density accuracy of ±0.5 kg/m^3 (0.03 lbm/ft^3, Micro Motion's current liquid density specification) on a gas of approximately 32 kg/m^3 (2.0 lbm/ft^3) was required. By calibrating the meter on densities very close to the actual operating condition and by restricting the fluid velocity through the sensor, the meter performed up to the customer's expectations. This effort indicated that Micro Motion has the capability to accurately measure gas density. Future work will be done in the area of calibration to improve this measurement.

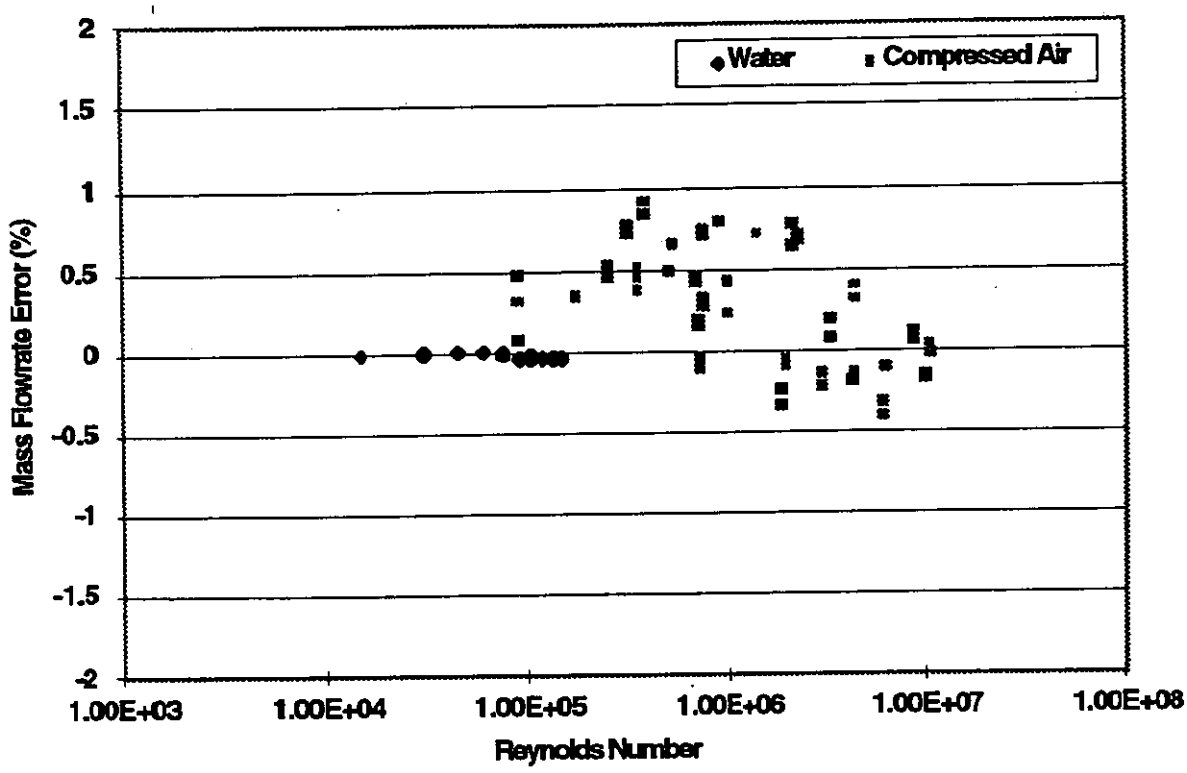
CONCLUSIONS

Micro Motion Coriolis mass flowmeters are an accurate alternative for measuring the mass flow rate of gases. All tested accuracies are better than ±2.0% of rate, with much of the data better than ±0.5%. The meters are largely insensitive to gas temperature and pressure and provide a linear signal over a very wide flow range. Normal Micro Motion sizing guidelines should be followed when using a meter in its lower range; turndown considerations will affect the accuracy due to zero stability, although the Elite meters provide good zero stability and will therefore be useable at low flow rates. High velocity flow applications are to some extent self-limiting due to pressure drop considerations. In those applications where pressure drop may not be a problem, however, the gas velocity in the sensing element's tubes should be limited in accordance with Micro Motion recommendations.

The measurement of gas density is also possible. Fundamentally the meter can accurately measure density. Calibration improvements are key to making a better gas density measurement. Work is continuing to fully define the capability of Micro Motion meters on gas applications. The data presented herein is based on one meter of each size. Future tests will be conducted to test multiple meters in all sizes and employ a statistical analysis to develop performance capabilities and specifications.

REFERENCES

1. Presented by Peter van der Kam, Gasunie Research, Groningen, Netherlands, "Intercomparison Exercise of High Pressure Test Facilities within GERG", 3rd International Symposium on Fluid Flow Measurement, San Antonio, Texas, March 20-22, 1995.



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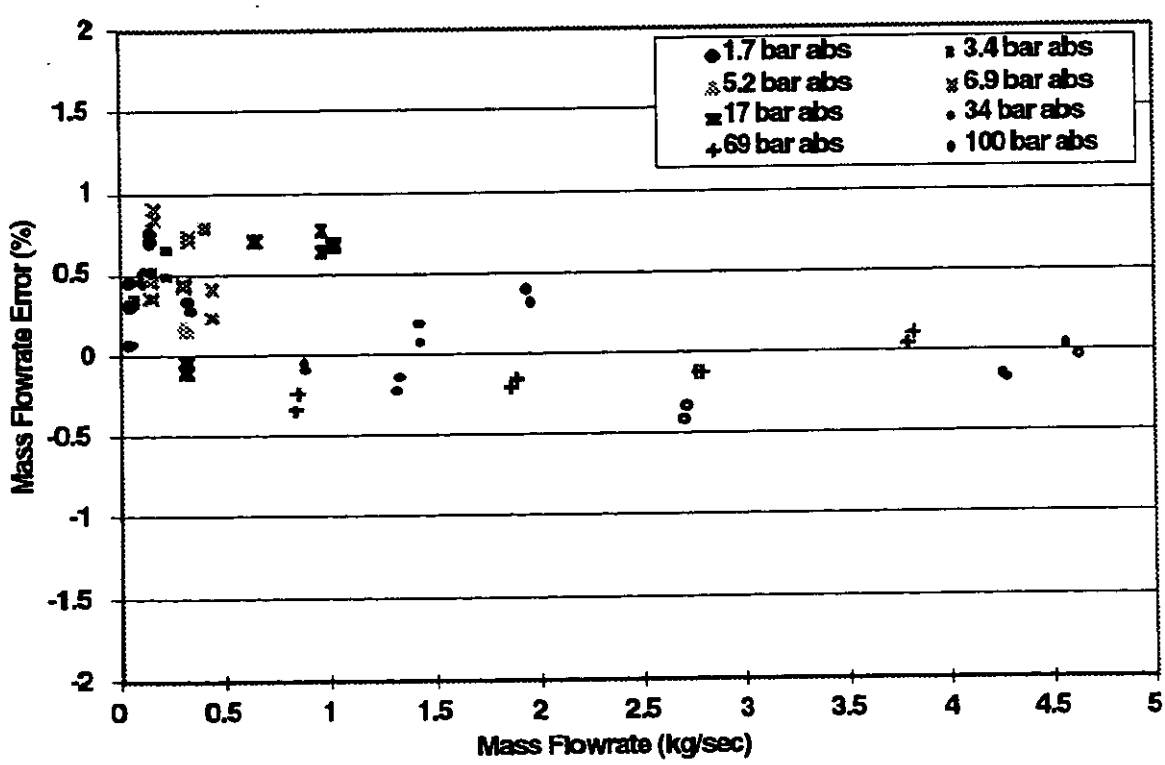
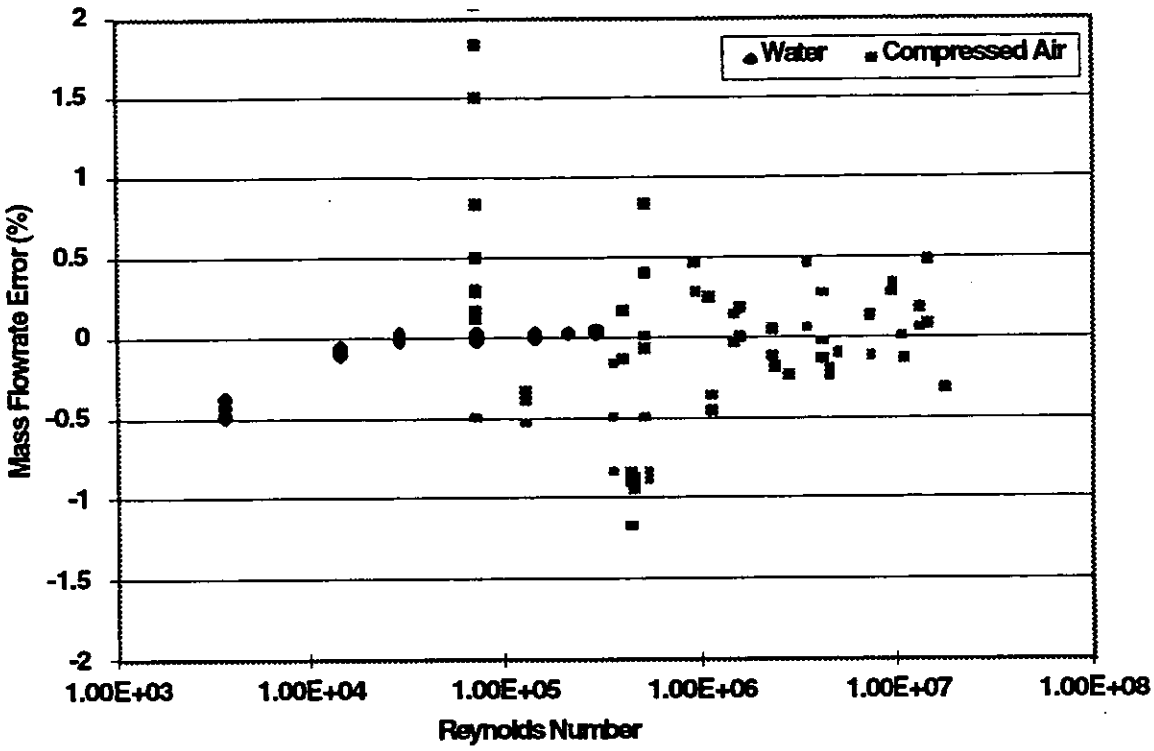


b)

Figure 1- Micro Motion CMF100 Performance:
a) Mass Flowrate Error (%) vs. Re for water and air,
b) Mass Flowrate Error (%) vs. Mass Flowrate (kg/sec) for air



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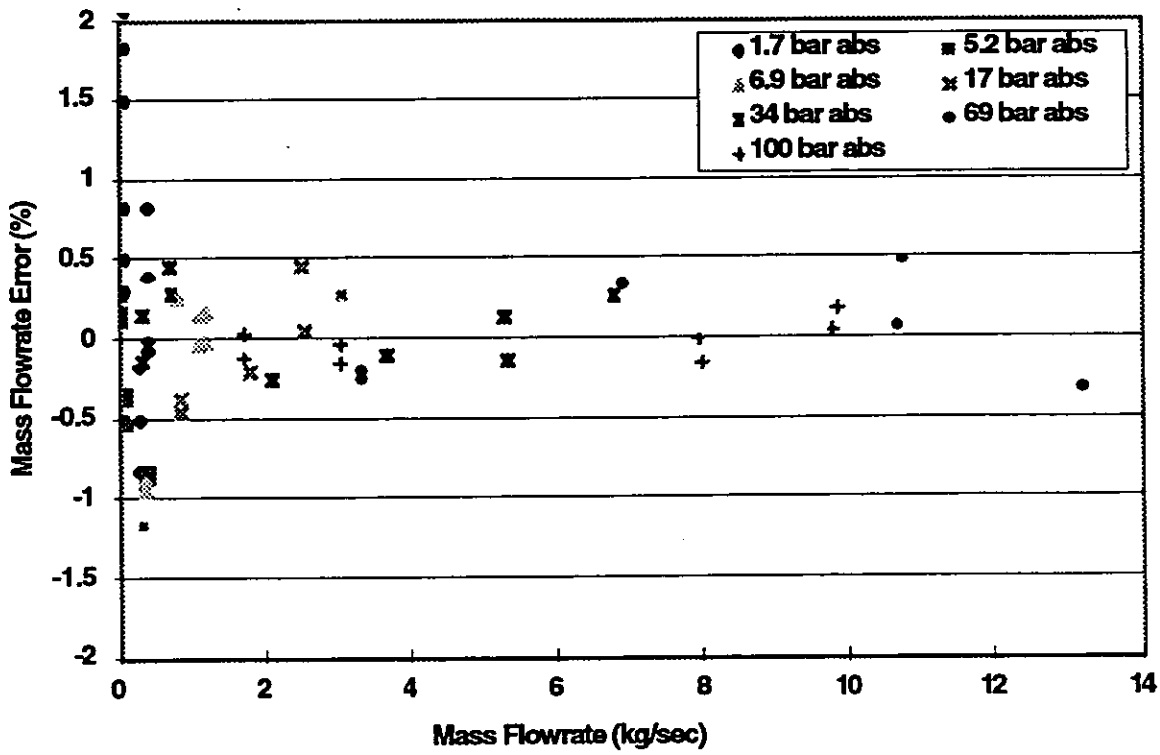
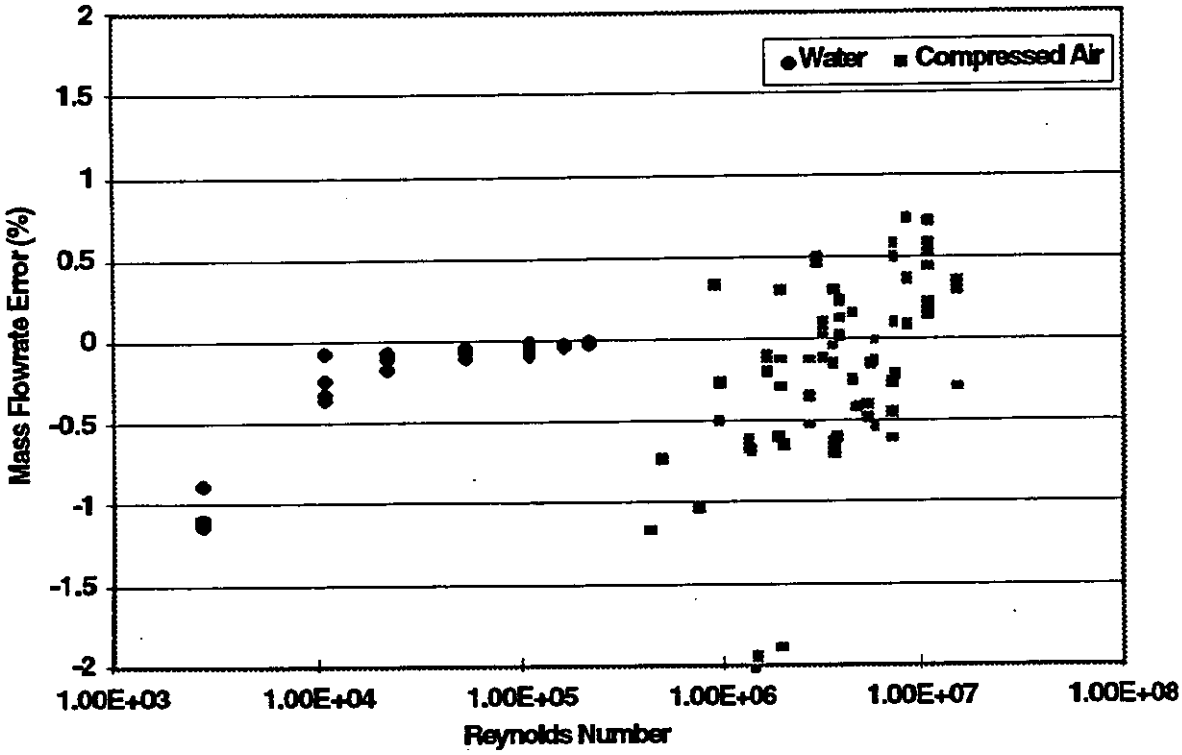


b)

Figure 2- Micro Motion CMF200 Performance:
a) Mass Flowrate Error (%) vs. Re for water and air,
b) Mass Flowrate Error (%) vs. Mass Flowrate (kg/sec) for air



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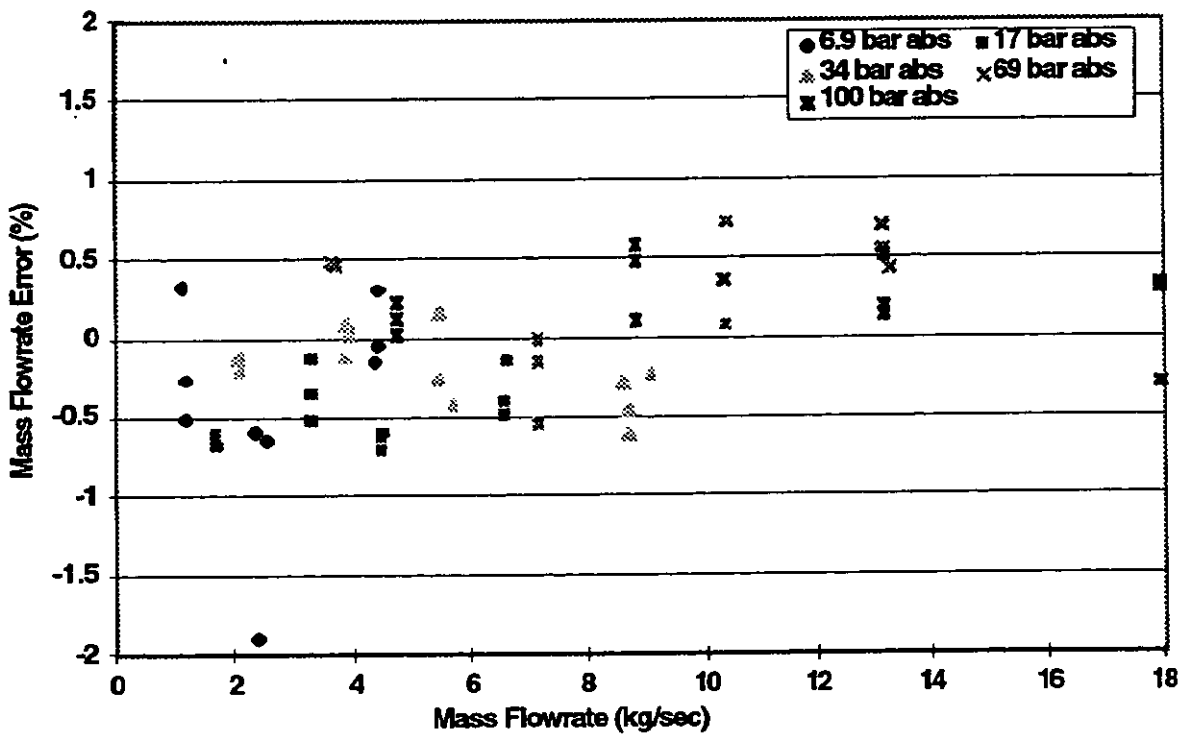
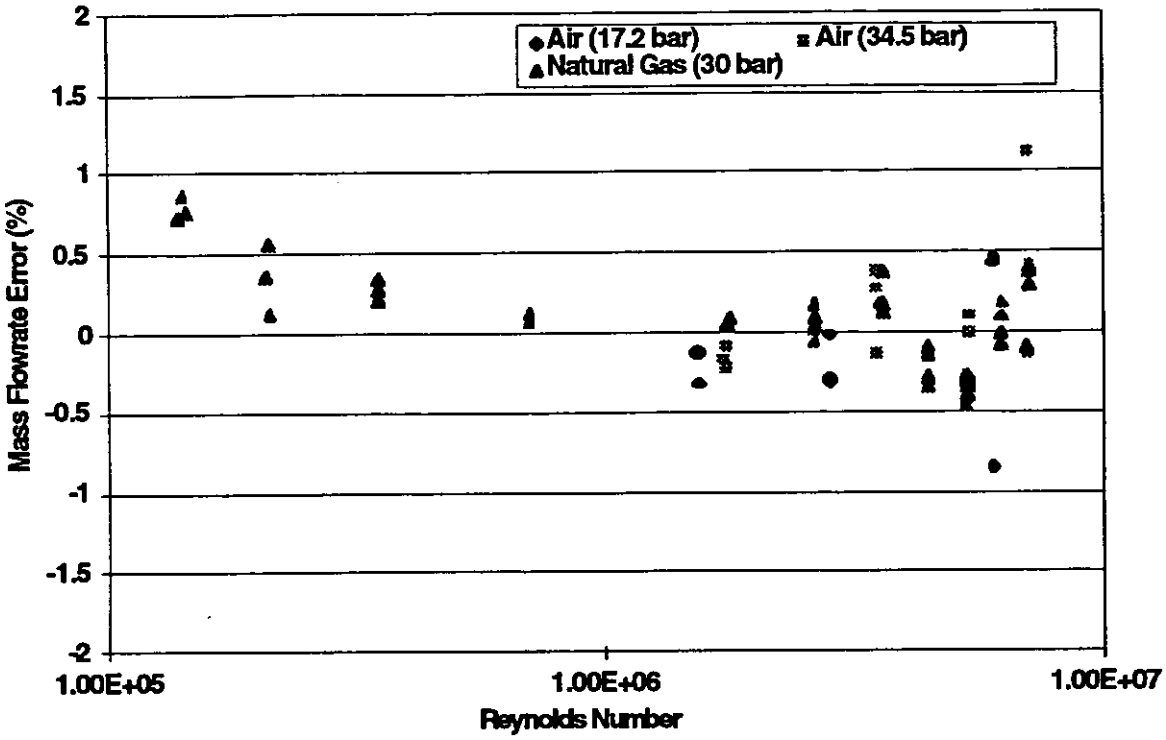
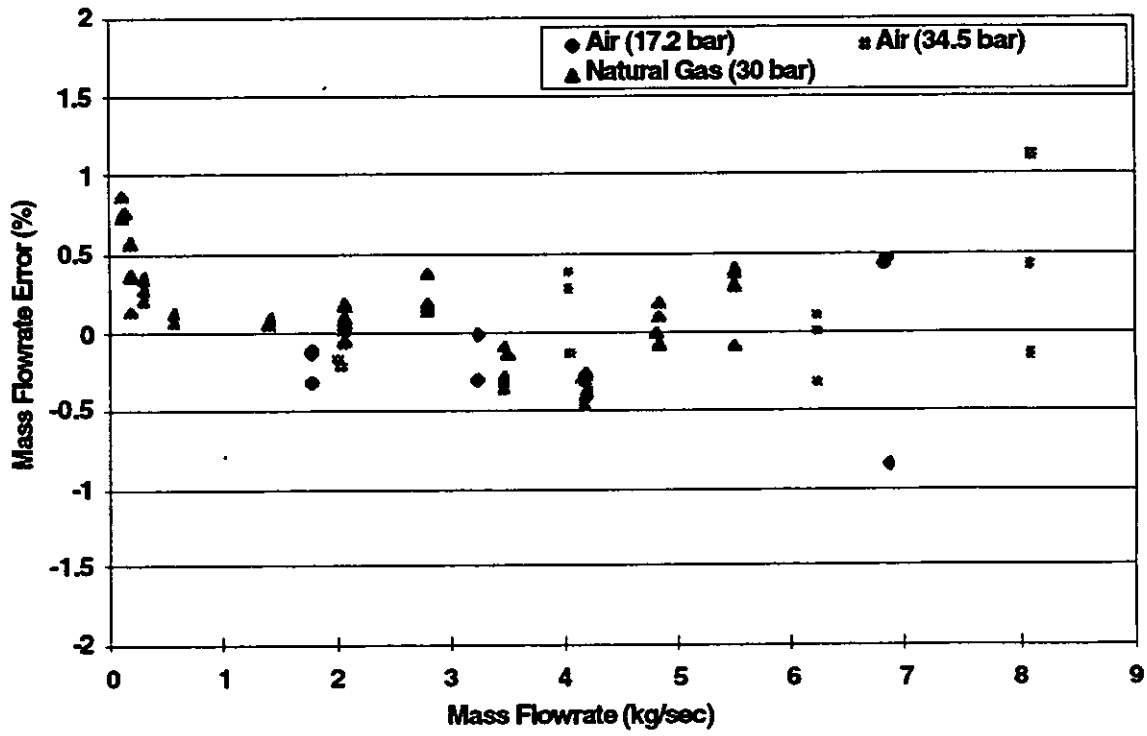


b)

Figure 3- Micro Motion CMF300 Performance:
a) Mass Flowrate Error (%) vs. Re for water and air,
b) Mass Flowrate Error (%) vs. Mass Flowrate (kg/sec) for air



a)



b)

Figure 4- Micro Motion CMF300 Performance:
a) Mass Flowrate Error (%) vs. Re for air and natural gas,
b) Mass Flowrate Error (%) vs. Mass Flowrate (kg/sec) for air and natural gas

Coriolis Flowmeters for Gas Measurement

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ABSTRACT

This paper demonstrates Coriolis mass flowmeters (CMF) can provide a solution for measuring the mass flowrate of gases directly, i.e. no knowledge of the gas properties is required. The test results for compressed air and natural gas presented here were obtained using a standard factory water calibration. This demonstrates properly designed CMF are linear devices and can provide accurate results independent of gas composition over wide pressure and mass flowrate ranges.

INTRODUCTION

Coriolis flowmetering has become increasingly popular over the past 10 years, especially for liquid applications. The primary advantage lies in the fact that mass flow rate is measured directly; small temperature and pressure compensations are required to adjust for changing stainless steel properties of the sensor itself, but these corrections are very small and independent of fluid properties. A direct mass flow rate measurement of gas is especially appealing because of the issues surrounding gas compressibility. A Coriolis mass flowmeter is a good measurement alternative because, as with liquids, it measures mass flow rate directly and addresses the complexities of density changes intrinsically.

A Coriolis meter requires two components: an in-line sensing element and a transmitter which interprets the signals from the sensor and converts the signals into useable outputs, usually pulse, analog (4-20 mA), and digital outputs. The sensing element usually consists of a manifold which splits the flow into two parallel paths. Two parallel tubes are vibrated at a resonant frequency of the system, similar to a tuning fork. As the flow passes through the tubes the fluid momentum coupled with the oscillatory motion created by the vibration induces a Coriolis force along the length of the tubes. This force translates into a phase shift (or Δt) along the length of the tube. The Δt is directly proportional to mass flow rate. Two electromagnetic sensors ("pickoffs") are located on opposite legs of the flow tubes. The vibration of the tubes generates sinusoidal signals on the pickoffs, which are shifted in phase due to the Coriolis force. The Δt between the two sinusoidal signals is then measured by the transmitter and mass flow rate is calculated.

When the stainless steel flow tubes change temperature, the material properties change slightly. At elevated temperature Young's modulus decreases which decreases the stiffness of the tube. This stiffness change affects the mass flow rate signal linearly by about 5% per 100 °C for a 316SS sensor. An RTD is mounted to the tube so that a correction can be made for the changing steel properties due to the temperature change.

To a much smaller degree, pressure influences the mass flow measurement. At elevated pressures the flow tube stiffens slightly due to the radial stress imparted by the fluid pressure. Typical values range from essentially unmeasurable for small sensors to approximately 0.08% per 6.9 bar (100 psi) for larger sensors. In lower pressure applications pressure compensation is not required since the effect is small. In high pressure applications, if the pressure is stable, the calibration constant can be biased appropriately to adjust for the influence of pressure and no compensation is required.

Due to the high quality tubing and tightly controlled manufacturing processes, the temperature and pressure constants are very consistent from one sensor to the next. Adjustments to the mass flow signal are therefore easy and repeatable from sensor to sensor.

Prior to operating the meter in any application, the transmitter must be zeroed. Zero flow must be established at conditions as close to the meter operating conditions as possible. The zero algorithm of the meter is activated by simply pushing a button on the transmitter. Zeroing relates the internal meter signals that arise due to residual installation effects to an actual zero flow condition.

In the following sections, test results are presented for Coriolis mass flowmeters (CMF) measuring compressed air and natural gas. Mass flowrate accuracy is determined as a function of gas pressure and mass flowrate using a factory water calibration. Results indicate properly designed CMF can provide accuracies up to ±0.5% over a wide range of pressures and mass flowrates.

COMPRESSED AIR TEST RESULTS

In 1992, gas measurement testing on Micro Motion's new Elite (CMF series) Coriolis was begun at the Colorado Engineering and Experimental Station, Inc. (CEESI) in Nunn, Colorado, USA. Based on the performance of the Elite meters on liquids, ±0.10% ± zero stability, it was anticipated that the new meters would also be capable of accurately measuring gas over a very wide mass flow range. The two primary advantages of the Elite meters over previous models (i.e. model D meters) are the superior zero stability making the meters accurate at low mass flow rates, and improved noise immunity which improves the signal stability (i.e. repeatability) during noisy, high velocity flows.

The results of testing performed at CEESI on the CMF100, CMF200, and CMF300 meters (25, 50, and 75 mm, respectively) are shown in Figures 1, 2 and 3. The figures contain post-processed data which includes the known pressure effect for each sensor size. The pressure effect is due to the slight stiffening of the sensing element tubes and was characterized on high pressure water.

Figures 1a), 2a), and 3a) show the mass flowrate error versus Reynolds number (Re) for the water calibration and compressed air test results. These results are shown solely to demonstrate that the water calibration for a properly designed CMF can be used for gas measurements. (Note: $Re = \rho VD/\mu$, where ρ= fluid density, V= flow tube fluid velocity, D= flow tube diameter, and μ= fluid viscosity.)

To understand the gas measurement performance of a CMF, plots of mass flowrate error versus mass flowrate need to be examined. Figures 1b), 2b), and 3b) contain this data for the compressed air test results as a function of air pressure (from 1.7 to 100.0 bar). The turndowns for the air data in these figures are 100:1 (CMF100), 280:1 (CMF200), and 50:1 (CMF300), respectively. Figure 2b) clearly shows the zero effect present in the CMF200 which is typical of a CMF with a large turndown.

As with many instruments, there is a small uncertainty associated with the zero of a Coriolis meter. As the mass flow rate decreases, the zero becomes a larger portion of the error as a percentage of rate. The performance of Coriolis meters at low flow is especially important for low density gases at low pressure (less than 6.9 bar) or low molecular weight (e.g. hydrogen gas). Velocity and pressure drop considerations in low gas density applications force the size of the sensing element to increase. This, however, forces the mass flow rate into the lower range of the selected sensor (i.e. high turndown) where the mass flow rate signal is small. The zero uncertainty, or zero stability, of the meter becomes critical in these applications if acceptable accuracy is to be maintained.

Three important points should be noted regarding the results from all three meter sizes:

1) **The flow calibration constant used for all testing was established on water at Micro Motion and was never changed.** To better than 2% the factory calibration constant is accurate over a very wide density range - 1000 kg/m^3 (water) to 2 kg/m^3 (air at 1.7 bar). In general, the errors are less than 0.5%. The calibrations should also be viewed in the context of the ±0.5% lab accuracy at CEESI.

2) **Typical accuracies for all three meter sizes are better than ±0.5%, with all data better than ±2% over a wide mass flowrate and pressure range.**

3) **The meters were zeroed only prior to the testing, indicating that the meter zero was stable for each sensor over the entire pressure range tested.** This is especially important for low flow rates where the zero plays a large role in the expected accuracy.

As indicated by the unchanging flow calibration factor over the entire pressure range, the mass flow measurement is independent of density. The air results from CEESI and the natural gas data presented below suggest that the mass flow rate measurement is independent of fluid properties. As previously discussed, temperature and pressure measurements are made to correct for changing properties of the sensing element itself, but the corrections afforded by these measurements are small and independent of the fluid properties.

NATURAL GAS TEST RESULTS

To examine the effect of gas composition on meter performance a CMF300 (75 mm meter) was tested on compressed air at CEESI and then on natural gas at the Ruhrgas/PIGSAR facility in Dorsten, Germany. The PIGSAR volumetric measurement uncertainty is 0.25% and the density measurement uncertainty is 0.15%. Thus the worst case mass flowrate measurement uncertainty of the PIGSAR facility is 0.40%. The CEESI facility mass flowrate uncertainty is stated as 0.50%. The air and natural gas data has also been pressure compensated as discussed earlier.

Initial comparison of the test results from the two facilities revealed an average mass weighted bias of 0.48% in the PIGSAR natural gas data while the CEESI air data had a negligible bias. The PIGSAR natural gas data calibration error shown in Figure 4 has been adjusted by -0.48% for comparison purposes. Future efforts will be directed towards understanding the apparent lab bias (see Reference [1] for example) exhibited in the test results.

Figure 4a illustrates the mass flowrate error versus Re for the air (17.2 and 34.5 bar) and natural gas (30 bar) test results. The same data is replotted in Figure 4b to show the mass flowrate error versus mass flowrate. Several results are apparent in the plots.

Typical accuracies are again ±0.5% for the two gases over a wide range of Re and/or mass flowrate ranges. Figure 4b again shows the zero effect present at large turndowns in the natural gas data. The natural gas data meets the current Micro Motion gas specifications, ±0.5% ±Z.S., over a 50:1 turndown (7 to 333 kg/sec at 30 bar).

The repeatability of the air data decreases while the repeatability of the natural gas changes little at high Re/mass flowrates. This may be due to the inherent testing differences between the two standards used at the two facilities, i.e. turbine meters/sonic nozzles at PIGSAR/CEESI, respectively.

Main Index

North Sea FLOW Measurement Workshop 1995

Paper 18:

INSTALLATION EFFECTS ON A MULTIPATH ULTRASONIC FLOW METER DESIGNED FOR PROFILE DISTURBANCES

5·3

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INSTALLATION EFFECTS ON A MULTIPATH ULTRASONIC FLOW METER DESIGNED FOR PROFILE DISTURBANCES

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Summary

Previous work on ultrasonic flowmeters (as carried out within the "Ultraflow" project presented at North Sea Workshop in 1994) has demonstrated that, even with the use of multipath configuration, the design of an ultrasonic meter could be sensitive to profile disturbances. A complementary work, on a different design from that used in the "Ultraflow" project, was performed on a DN300 meter operating on natural gas at pressures from 15 to 60 bar. This kind of work is necessary for the developpement of the installation standards.

This paper is an extract from the final joint report and individual test results obtained on the test facilities of Gasunie, Ruhrgas and Gaz De France. The tests performed under ideal flow conditions allow the evaluation of meter stability over the range of flow velocity and the influence of gas pressure. The effects of upstream disturbances (1 bend 90°, double bends out-of-plane and pressure reduction) are presented.

1 - Introduction

Ultrasonic gas flow metering is quite a recent technique. This type of gas meters has been commercially available for nearly 8 years and is entering the European market. Some large gas companies have already bought these meters in view of operational use. The recent multi-path ultrasonic gas flow meter can be considered a promising alternative to turbine meters or orifice plates for accurate measurement of large volume flow.

In ideal flow conditions, all the multi-path ultrasonic gas flow meters run properly. In theory, upstream disturbances have little effect on the multi-path ultrasonic gas flow meter. Nevertheless, recent studies regarding the effect of installation conditions and presented last year at the North Sea Flow Measurement Workshop [1], reveal that metering with multi-path ultrasonic technique can be disturbed if the meter is installed with less than 10D[1] of straight pipe from the disturbing pipe configuration or dowstream of a pressure reducer. This project was carried out in the framework of "Ultraflow" on DN150 and DN300 meters using 4 paths equiped with two transducers which measure the transit time with and against the direction of gas flow.

The actual meter under test is a DN300 meter. Its flow range measurement is larger than the previous meters and the metering uses 5 paths with 3 single reflection and 2 double reflection paths covering the pipe area and designed to avoid the effects of flow profile disturbances on the measurement.

The testing of this 5 path ultrasonic flow meter is performed in an EGMG project in which the participants are Ruhrgas (RG), Gasunie (GU), Gaz De France (GDF) and the meter manufacturer. Ruhrgas acts as the project manager. The aim of this project is to qualify this meter in terms of repeatability, reproducibility, effects of pressure, effects of transducer exchange, and to perform a series of tests to demonstrate the effect on the meter of upstream disturbances such as asymmetries, swirl and fluctuations caused by different 90° bend, double bends out-of-plane configurations and pressure reduction. Although it was not expected that the meter would

[1] straight lenght of 10 diameter long

run properly, the 2D distance between the configuration and the meter was also investigated. Ideal flow calibrations with diffent pressure, under fully developed flow conditions, were performed on each test facility. These tests were used as a reference to determine the effects of the different configurations and to detect the difference between the test facilities.

The test programme was carried out on the high pressure flow metering facilities of the gas company participants from September 1994 to July 1995. The descriptions of the test benches and their calibration uncertainties are given in [2]. These uncertainties are in the order of 0.3 % for each test bench. The impact of 90° bend installed at different distances was investigated by Ruhrgas on the Lintorf high pressure test rig. The swirl effect tests in accordance with the provisions of ISO 9951 for turbine meter testing with different straight pipe lenght between the disturbance and the meter were carried out by Gasunie in the Bernoulli Laboratory in Westerbork. Tests with the ultrasonic flowmeter turned on its longitudinal axis and transducers exchange tests were also carried out in both laboratories. Gaz De France completed the tests with the meter situated dowstream of a pressure reducer with and without a noise reducing part, and tests with the meter situated upstream of the pressure reducer. Table 1 shows all test configurations examined by the participants.

Test		Laboratory
Ideal calibration	15 bar	RG, GDF
	25 bar	RG, GDF
	50 bar	RG
	60 bar	GU
Transducers exchange	15 bar	RG
	60bar	GU
Perturbation 90° single bend		
Distance 10D / 0° and 54°	15 bar	RG
	25 bar	RG
	50 bar	RG
Distance 5D / 0° and 54°	15 bar	RG
	25 bar	RG
Distance 2D / 0° and 54°	15 bar	RG
	25 bar	RG
	50 bar	RG
Perturbation 180° double bend		
Distance 10D LL / 0° and 54°	60 bar	GU
Distance 10D HL / 0° and 54°	"	GU
Distance 5D LL / 0° and 54°	"	GU
Distance 5D HL / 0° and 54°	"	GU
Distance 2D LL / 0° and 54°	"	GU
Distance 2D HL / 0° and 54°	"	GU
Distance 10D HL / -54°	"	GU
Perturbation due to pressure reduction		
5D downstream with noise reducer	15 bar	GDF
5D downstream without noise reducer	15 bar	GDF
5D upstream with noise reducer	15 bar	GDF

TABLE 1 : test programme divided between laboratories

2 - Description of the meter

The operating principle of the ultrasonic meter is based on the transit time method with direct digitising of each individal sound impulse. The flow meter under test has a 5 path configuration with 3 single reflection "axial" paths and 2 double reflection "swirl" paths in and against the direction of the flow. In this way, it is possible to pick up swirl effects in the flow and correct them by calculation. The housing diameter is 306 mm. The maximum flow rate is defined as 8000 m^3/h, i. e. the size of the meter is G5000 (maximum gas velocity = 30 m/s). This is twice larger than turbine meters of the same size. The minimum flow rate can be considered very low because there are no friction effects occuring at low flow rate on the metering as on volumetric meters. Its maximum pressure is 80 bar.

3 - Test configuration

The "ideal" calibration tests were performed prior to the disturbance tests. On each facility, the meter was installed with a large length of straight pipe upstream (at least 20D) and at different pressures. The calibrations were carried out with the meter installed horizontal with original transducers. The same hardware and parameters set-up were used throughout the programme with the exception of the density value at Westerbork.

The swirl disturbance consists of 2 bends out-of-plane as described in ISO 9951 for turbine meter testing. The flow upstream of this configuration is stabilised by a flow straightener. The asymmetric flow caused by the first bend is turned into a swirl by the second bend. The selected configuration creates an anti-clockwise so called "Low Level" swirl (LL). To create "High Level" swirl (HL), a half moon plate is installed between the two bends. The swirl produced is also anti clockwise but the swirl angles are approximately 2 to 3 times larger than for the "Low Level" swirl. The "Low Level" should represent the worst swirl disturbance in normal piping. The meter has been tested with 2D, 5D and 10D of straight pipe lenght between the swirl configuration and the inlet of the meter at a pressure of 60 bar. The tests were carried out with the meter mounted horizontally (noted 0°) and turned to 54° on its own axis.

The impact of asymmetric flow created by a 90° bend installed at distances of 2D, 5D and 10D upstream of the meter was investigated at three pressures of 15, 25 and 50 bar. The meter was first installed in a horizontal position (noted 0°) and rotated 54° from its body axis.

The influence of the exchange of transducers and electronics unit on fully developped flow profile was studied. This represents the case where the meter has one or more damaged transducers which have to be replaced. The question was whether the basic calibration is still valid with exchanged transducers. These test series were performed with one pair of extra transducers which replaced 2 transducers in various combinations.

The programme was completed with the test series of high level disturbances created by a pressure reducer. The pressure reducer used for these tests was a RMG axial flow regulator, the nominal diameter of which is DN80. It could be mounted with a noise reducer part, resulting in DN300. The necessary adapter parts were specially designed for the tests to join the regulator and the noise reducer to the pipes. Tests were carried out with the ultrasonic flow meter situated dowstream (5D) of the pressure reducer with and without the noise reducing part, and with the meter situated upstream of the pressure reducer (5D). For each of the three configurations, 1 test were carried out with a pressure reduction of 5 bar from 25 to 20 bar and from 20 to 15 bar, together with the test with the pressure reducer fully opened.

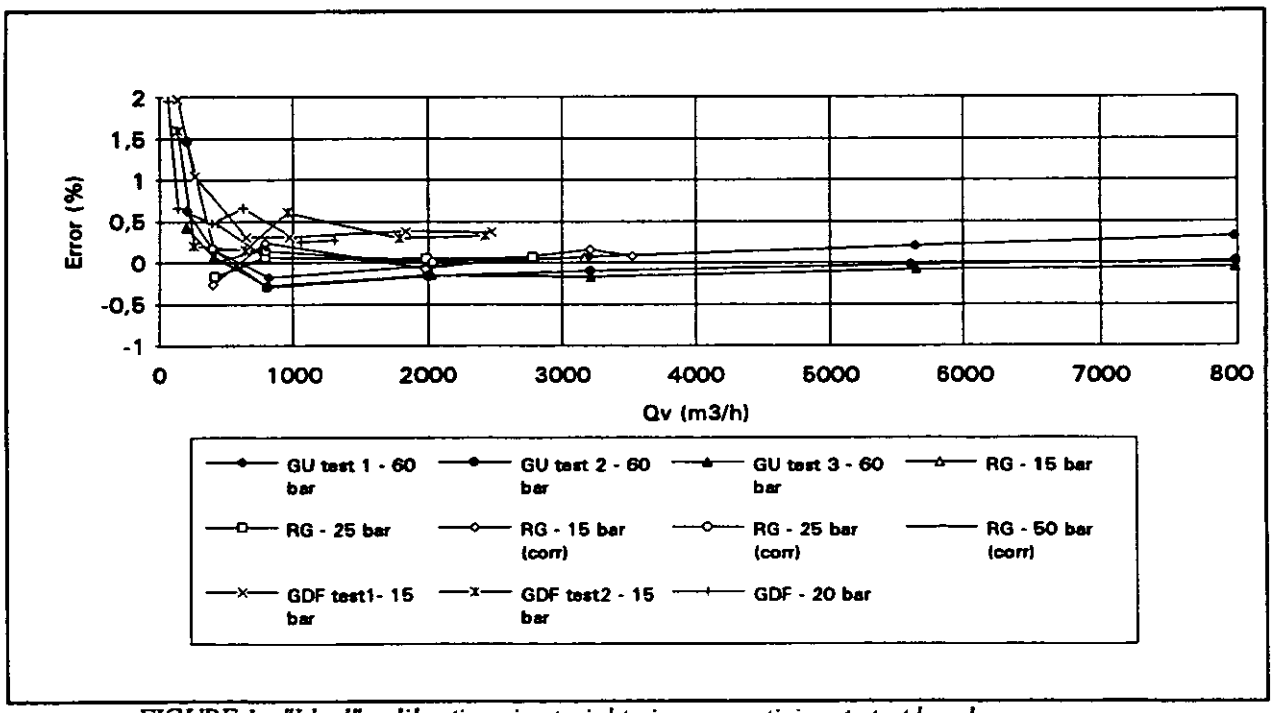

FIGURE 1 : "Ideal" calibrations in straight pipe on participants test bench

4 - Tests on ideal conditions

4.1 - Results of the ideal calibration tests

For the "ideal" calibration test, Gasunie carried out 3 calibrations at 60 bar, before and after the double bend tests and at the end of its programme. The Ruhrgas and Gaz De France error curves were measured with the meter mounted under ideal conditions at 15 and 25 bar before their test programme. Figure 1 shows the mean results of these test series.The meter was tested over a period of 10 months without any noticeable long term variation in calibration.

The overall spread of results between the benches is within ± 0.5 % taking into account individual points on the flow range from 10 to 100 % of the maximum flow rate and within ± 1 % from 5 to 10 %. Morever, the mean values are within ± 0.3 % on the flow range from 10 to 100 % of the maximum flow rate. Here, the calibration curves remain within the permissible error defined by legislations as ± 1 % for the flow rate between 20 % and 100 % of the maximum flow rate and ± 2 % for the flow rate between 5 % and 20 % of the maximum flow rate.

The spread of the results also includes the effect of temperature (from 10 up to 21 °C), differences in natural gas composition (Groningen, Norway, Algeria etc.), transportation of the meter and its instrumentation and small differences in "ideal" calibration installation. Morever, a slight change in flow profile due to a different pipe roughness could explain some differences noticed on the Gasunie calibration tests. The pipe wall of the meter had been cleaned after an inspection between test 1 and test 2.

The influence of the test pressure on the meter error is negligible. The mean influence of the pressure is 0.08 % on the Ruhrgas calibration curve and the maximum variation of the mean error values is less than 0.4 % on the Gaz De France results except at the lowest test flow rate for which the variation reaches 1.3 %. Figure 1 shows the maximum difference between the 15, 25 and 60 bar laboratories' curves of nearly 0.75 % on the flow range from 5 to 100 % of the maximum flow rate.

At very low flow rates, the mean error is positive and shows more scattered values. The individual values of the meter error are much more scattered at low flow rates than at high flow rates. Table 2 presents the standard deviations calculated from the meter error obtained by the three laboratories on low and large flow rate. The standard deviation is generally below 0.1 % which proves a good repeatability of the metering system, except for the lower flow rates. The explanation for the large variation of the meter error at low flow rates (from less than 1 up to 5 % of the maximum flow rate) could be the sudden or gradual change of the velocity distributions obverved. This effect disapeared at higher flow rates due to the turbulence regime.

GASUNIE

Qv (m3/h)	σ(error)
810 - 8000	0.01
400	0.05
200	0.14

Pressure test = 60 bar

RUHRGAS

Qv (m3/h)	σ(error)
800 - 3000	0.05
400	0.12

Pressure test = 15 and 25 bar

GAZ DE FRANCE

Qv (m3/h)	σ(error)
630 - 2500	0.05 ***
400	0.04 **
260	0.31 *
135	0.50 ***
65	0.65 **

* Pressure test = 15 bar
** Pressure test = 25 bar
*** Pressure test = 15 and 25 bar

Table 2 : standard deviations of the meter error

During one test, the flow rate was increased at 145 % of the maximum flow rate to observe meter behaviour at very high flow rate. Some of the transducer signal was lost but since 60 % of the signals were accepted, the meter output is still reliable. The mean error was at this flow was + 0.33 %. Morever, some results were obtained for a very low flow rate down to 1 % of the maximum flow rate. The mean results are in the maximum permissible error although some individual values are out but still within ± 3 %.

4.2 - Exchange of transducers and electronics unit

The results of tests for which transducers and electronics unit positionned on the meter body were exchanged proved that there is no influence. The deviations between the straight pipe calibration with the original transducers and the calibrations with the meter equipped with an extra pair of transducers are always within ± 0.2 % of the mean values on the flow range from 10 to 100 % of the maximum flow rate.

5 - Results of the disturbance tests

5.1 - Perturbation 90° single bend

The results of the tests with a 90° bend installed upstream of the ultrasonic meter at a distance of 5D and 10D are presented in figure 2. It shows that the 10D straight lenght between the configuration and the meter gives acceptable results. The deviation of the meter error is less than 0.3 % for the measuring range from 10 to 100 % of the maximum flow rate. This deviation is within the ISO 9951 tolerance. The 5D distance results give a deviation of the measurements of - 0.7 % in the flow range from 10 to 100 % of the maximum flow rate. There is no significant influence of the pressure test on the metering system with both configurations.

The deviation of the meter error due to the 54° rotation of the meter on the 10D configuration is less than 0.1 %. It reaches nearly 0.2 % for the 5D configuration tests. These values do not deviate significantly from zero.

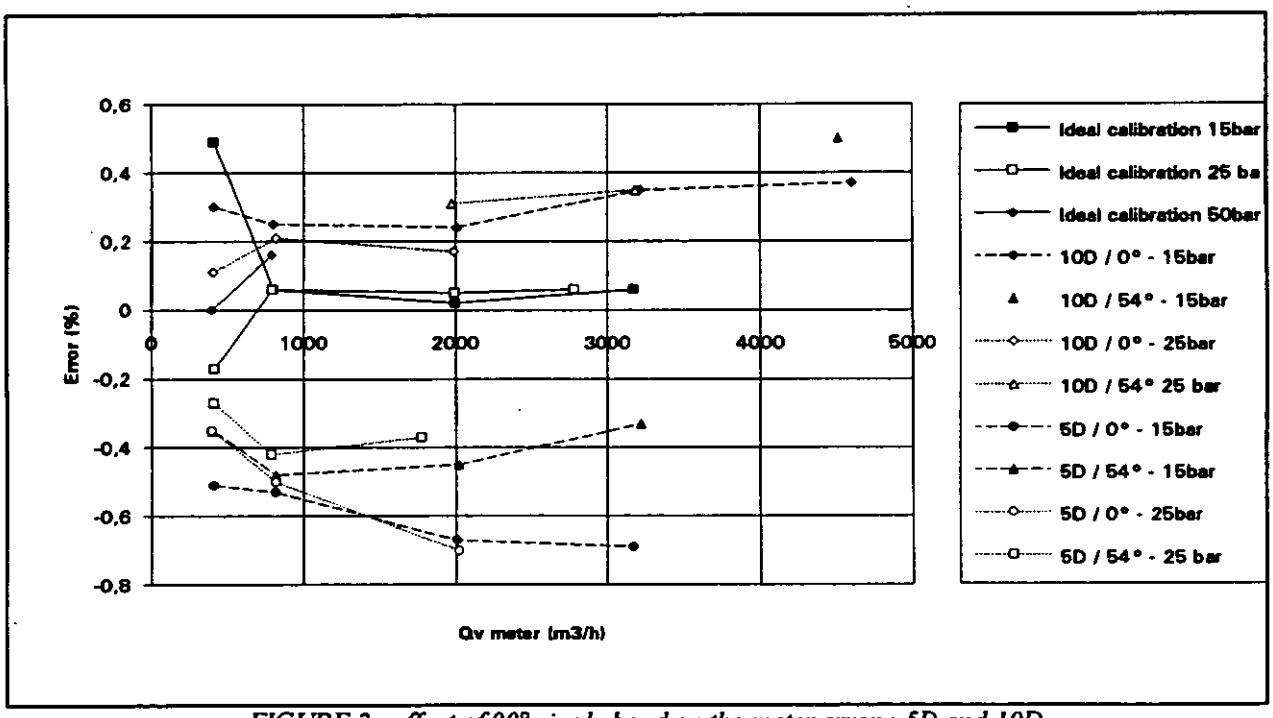

FIGURE 2 : effect of 90° single bend on the meter error : 5D and 10D

As presented in figure 3, the reduced straight length of 2D produced a considerable negative drop of the meter error curves. For all the pressure tests, the deviation of the error is roughly -2.0 % compared with the ideal calibration in large straight pipe length. The rotation of the meter on its body axis reduced the mean negative deviation close to the ideal calibration values. The influence of the pressure (15, 25 and 50 bar) is very low except near 400 m^3/h for which the deviation reaches 0.5 %.

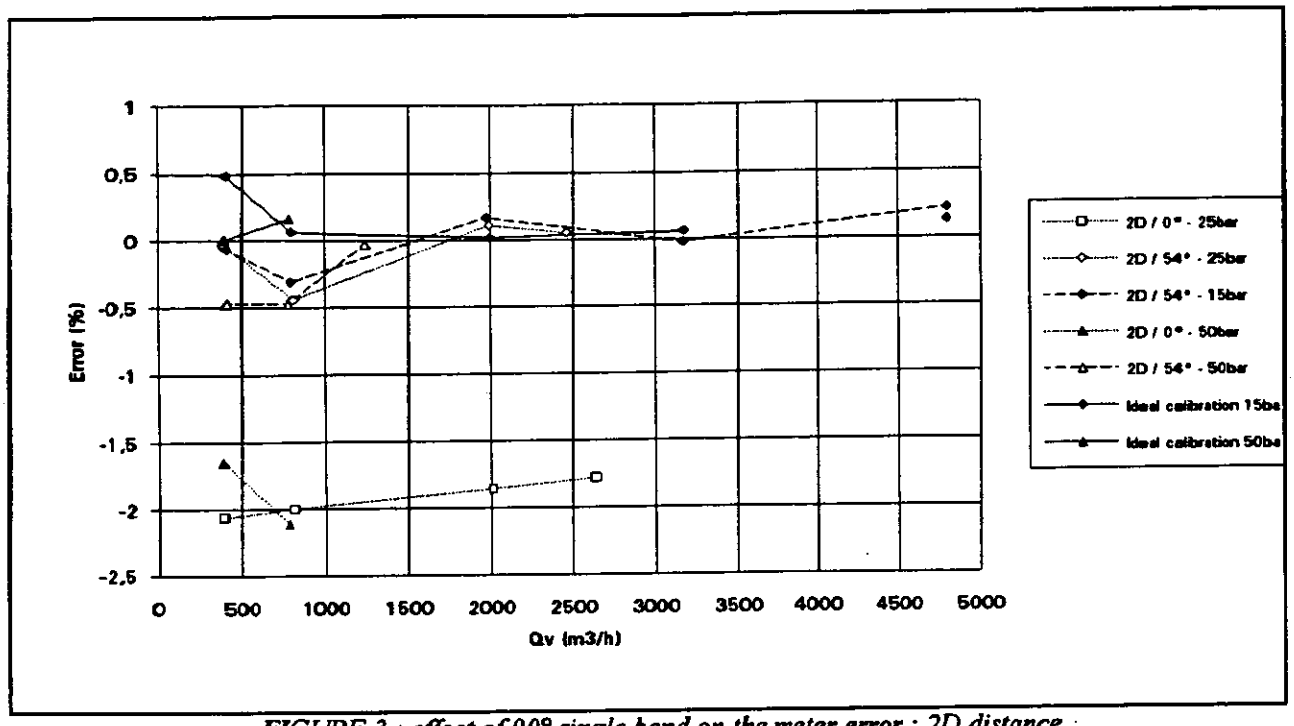

FIGURE 3 : effect of 90° single bend on the meter error : 2D distance

5.2 - Perturbation double bends out of plane

The curves of mean values in Low Level disturbance (LL) are presented in figure 4. The tests on swirling conditions prove that the results are more scattered than the test points of one particular test than the ideal calibration. At 2D distance, the error curves lie outside the defined error limits and show clearly the influence of the meter rotation. In the 5D and 10D, the curves are within the limits but there are slight differences caused by rotation of the meter.

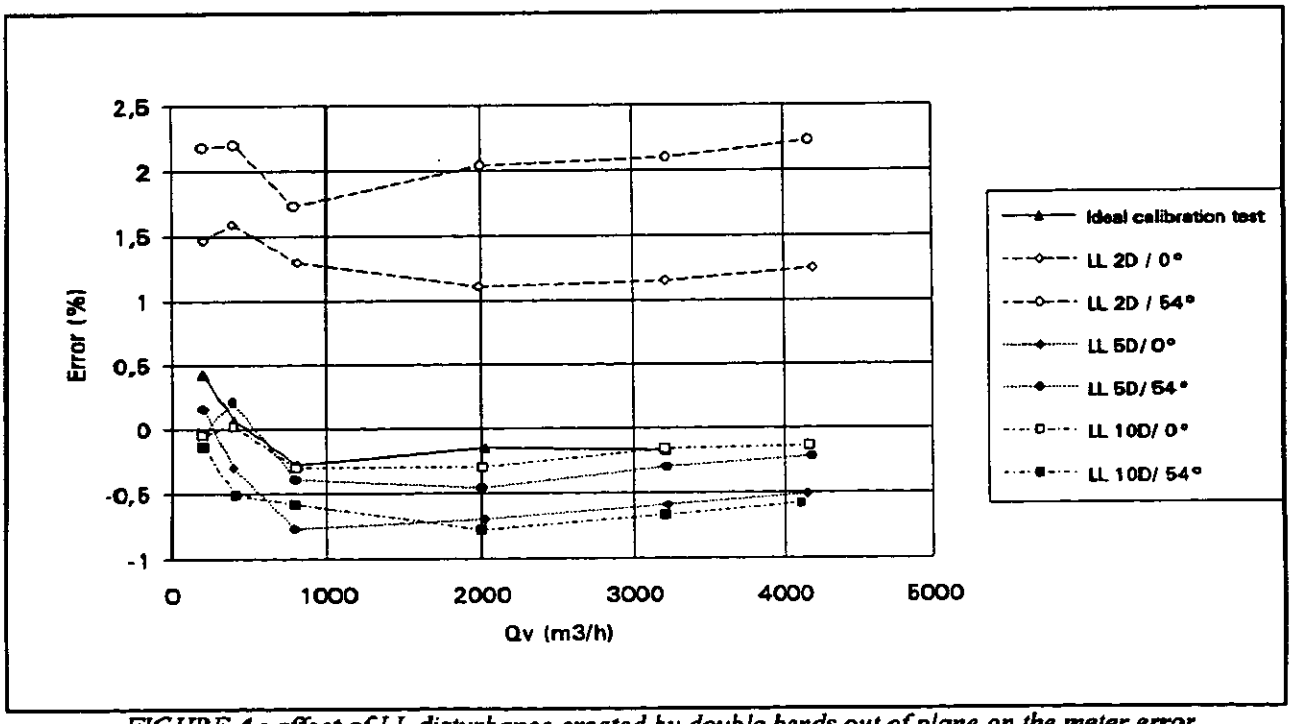

FIGURE 4 : effect of LL disturbance created by double bends out of plane on the meter error

Figure 5 presents the mean results obtained for the High Level disturbance tests (HL). For both 2D and 5D curves, there is a great difference between the horizontal (0°) and the rotation meter (54°) curves. Morever the results are more scattered than the Low Level values. At 10D, the curves lie within the the error limits but there is still some influence from the rotation of the meter. One of these curves is obtained with the meter rotated anti-clockwise on the axial position whereas the other rotation curves are obtained with the meter rotated clockwise.

At 2D distance, both Low and High Level disburbance may influence the meter reading and result in an unceeptable meter error, depending on the meter orientation. Nevertheless, the meter kept the signal in "High Level" pulsating flow. At 5D this effect vanished for the Low Level swirl but is still present for High Level disturbance. At 10D the meter errors are within the acceptable limits although dependent on the meter orientation.

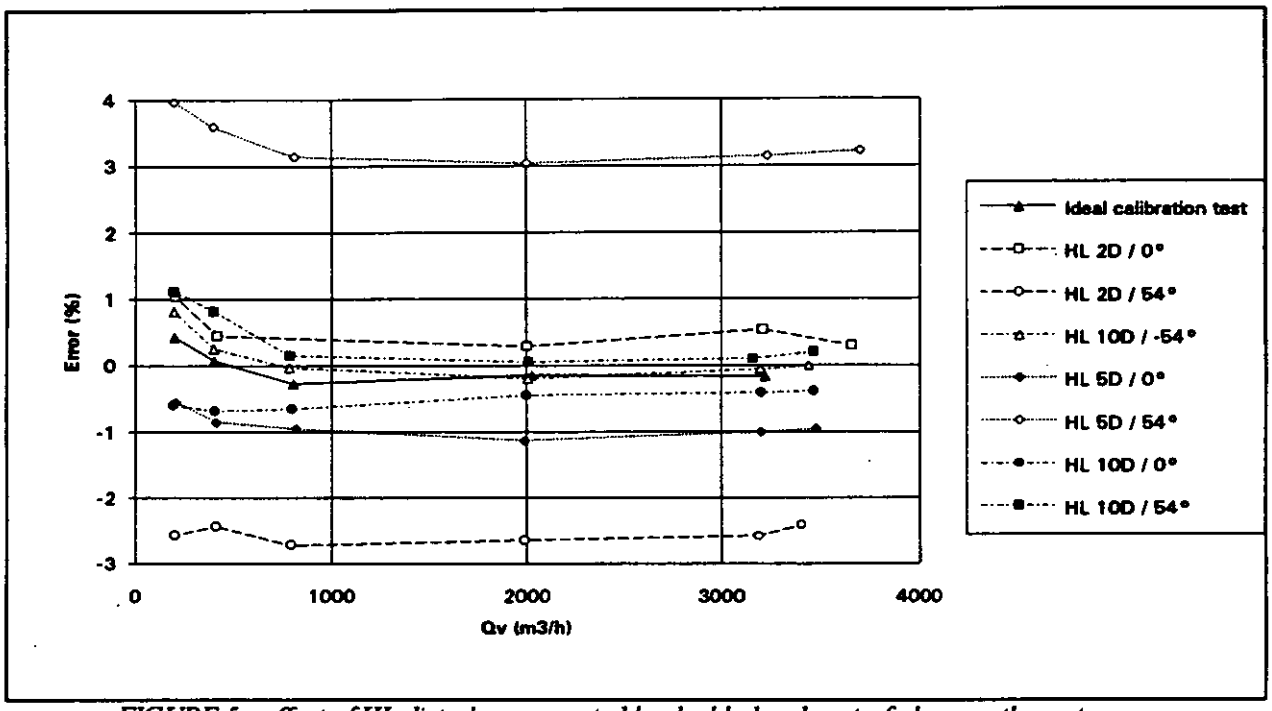

FIGURE 5 : effect of HL disturbance created by double bends out of plane on the meter error

5.3 - Perturbation due to pressure reduction

Only the tests with the pressure reducer fully opened or with the meter installed upstream of the regulator were completed. For the tests carried out with the meter installed dowstream of the regulator with a pressure reduction of 5 bar, the meter did not function at all for the two configurations and then the tests were aborted. Morever, with the same configuration and the pressure reducer fully opened, the meter did not operate correctly when the pressure reduction was in excess of 2 bar, except at very low flow rate. In some other cases, some of the 5 paths delivered an error signal which increased significantly the error of the meter.

The profile measurements recorded just upstream of the meter proved that the axial pressure reducer subjected the meter to a fully developed velocity profile with a high turbulence rate. Morover, during the test series, a very high noise was heard close to the regulator which gave us to believe that the meter was submitted to ultrasonic noise.

The results of the meter placed dowstream of a pressure reducer with and without its noise reducing part are presented in figure 6. Figure 7 shows the results with the meter mounted upstream of the pressure regulator with its noise reducer.

For a flow rate higher than 1000 m^3/h, the multipath ultrasonic flow meter is seriously affected by the presence of a pressure reducer installed upstream of the meter even if it is fully opened. For a pressure reduction of 5 bar, when the pressure reducer is installed downstream of the meter, the meter error became very high.

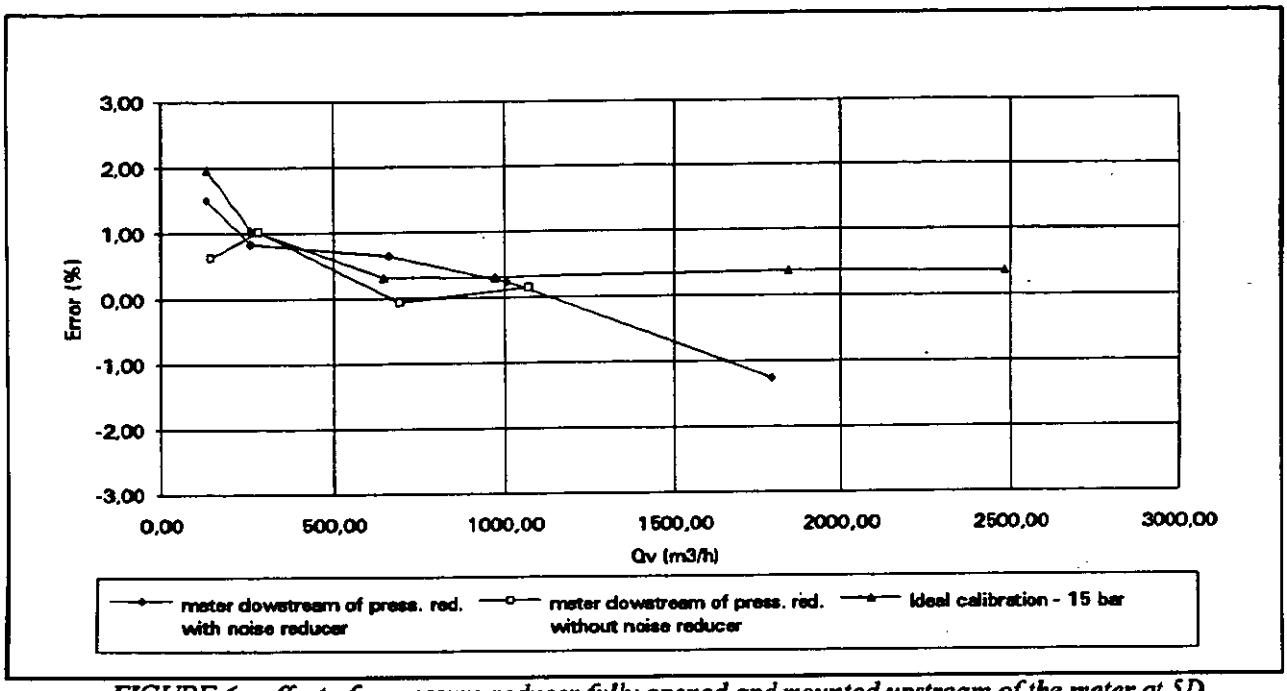

FIGURE 6 : effect of a pressure reducer fully opened and mounted upstream of the meter at 5D

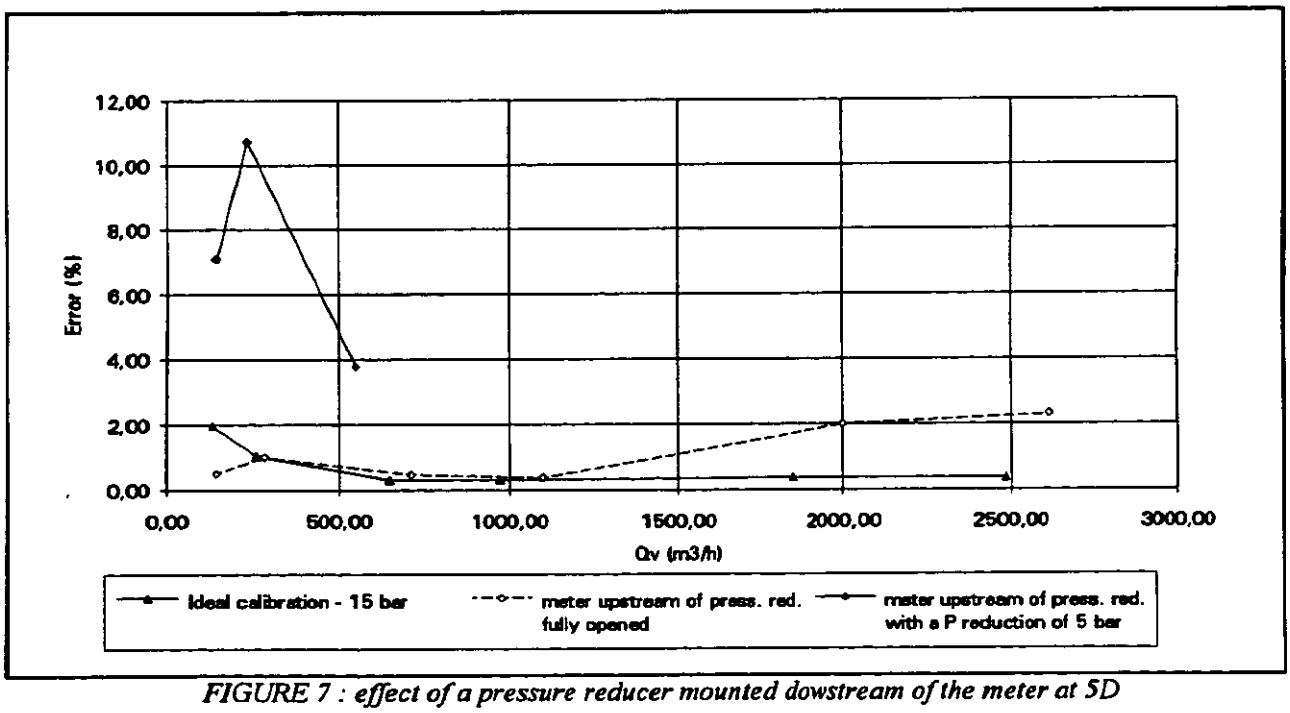

FIGURE 7 : effect of a pressure reducer mounted dowstream of the meter at 5D

6 - Conclusions

The maximum flow rate of the multipath ultrasonic flow meter is 8000 m^3/h which is twice the metering capacity of a turbine meter of the same size.

The exchange of 2 transducers or of the electronics unit has no significant influence on the meter performance.

All the individual calibration values obtained in ideal conditions were spread within ± 0.5 % on the flow range from 10 to 100 % of the maximum flow rate and within ± 1 % from 5% to 10 %. Morover, the mean results are spread within ± 0.3 % on the flow range from 10 to 100 % of the maximum flow rate and then are within the maximum permissible error range. Morever, some results were obtained for a very low flow rate down to 1 % of the maximum flow rate with a maximum error of 3 %. During the very high flow rate test (145 % of the maximum flow rate), the meter output was still reliable and the mean error was + 0.33 %.

The deviations obtained for the test of 10D distance 90° single bend are within the ISO 9951 tolerance. The influence of a clockwise rotation of the meter is still acceptable. The reduction of the distance between the single bend and the meter to 5D led to a mean shift of -0.7 % which is outside the ISO tolerance for the range from 10 to 100 % of the maximum flow rate. Nevertheless, the error curve for the 5D test is within the maximum permissible errors. The effect of the 2D distance is very great and the meter error is outside the maximum permissible error.

The 2D distance for the low level disturbance configuration may result in unacceptable error. The 5D and 10D distance between the double bends and the meter give acceptable results although some slight effects of the rotation of the meter still exist. The high level swirl causes great deviation of the meter error both at 2D and 5D distances. At 10D, the error shifts are within the acceptable limits (± 0.5 %) but are still slightly dependent on the orientation.

The installation of the meter close to a RMG pressure reducer (5D distance) is unacceptable without provisions to eliminate ultrasonic noise and other disturbances. Only slight pressure reduction (less than 1 bar) dowstream of the meter could be allowed. This conclusion may not be representative for other types of pressure reducers.

Some additional uncertainties on the ultrasonic flow meter due to disturbances are proposed in table 3 regarding the distance between the pipe configuration and the meter. All figures are given in percentages taking into account that the orientation of the meter is not defined.

	Ideal calibration	90 ° bend		LL swirl		HL swirl		Pressure reducer
distance	> 20D	5D	10D	5D	10D	5D	10D	5D
5 paths meter	0.5	0.7	0.3	1.0	1.0	3.5	1.0	Unacceptable

TABLE 3 : summary of proposed additional uncertainties due to disturbances

Acknowlegments

Thanks to all who contributed to the EGMG project by discussions and by carrying out the tests.

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North Sea FLOW Measurement Workshop 1995

Paper 20:

A PERFORMANCE STUDY OF A V CRONE METER IN SWIRLING FLOW

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A PERFORMANCE STUDY OF A V-CONE METER IN SWIRLING FLOW

by

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for presentation at

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SUMMARY

This report describes a test to evaluate the measurement accuracy of three 150 mm (6 inch) V-Cone meters of different beta ratios in swirling flow. The purpose was to establish the installation effects of this relatively new meter and to compare its performance with the widely-used orifice meters under similar conditions. The test, conducted in Chevron's low pressure air flow system, showed that the V-cone meter was significantly less affected by swirling flow in comparison with the orifice meter. Even in highly swirling flow (swirl angles up to 40 degrees), the flow rate measurements were within 0.5% of the no-swirl baseline measurement. The test at Statoil/K-Lab in natural gas at high pressure (7.5 MPa) confirmed the excellent performance of the V-Cone demonstrated in the Chevron test. Since V-Cone meters are not significantly impacted by swirls, they may be better suited for applications in cramped quarters (e.g. offshore platforms) than orifice meters. The V-Cone meter should be able to measure flow rates with reasonable accuracy even with upstream disturbances (out-of-plane elbows and/or header) locating as close as 10 pipe diameters from the meter without any flow conditioning.

INTRODUCTION

This report describes the results of testing V-Cone meters in swirling flow. Like an orifice meter, V-Cone meter is a differential pressure type meter based on the principle of correlating the observed pressure drop due to an obstruction in the line to the volumetric flow rate. As the name implies, the obstruction is a V-shaped cone hanging in the center of the pipe as shown schematically in Figure 1. This relatively new meter is manufactured and marketed by McCrometer Division of Ketema Inc., Hemet, California.

The meter manufacturer claims that the performance of V-Cone meters is not affected by non-ideal flow conditions. Reports on previous tests conducted with 50 mm (2 inch) and 100 mm (4 inch) V-Cone meters with disturbed flows (after a single elbow,close -coupled double elbows out-of-plane and a fully/ half-open valve) appear to support this claim.[1-4] This is in contrast to orifice meters which are known to be sensitive to non-ideal flow conditions that are usually caused by upstream elbows, valves, and other fittings. Swirl in the flow, typically generated in the piping system by two out-of-plane elbows, is generally considered one of the worst flow conditions in terms of causing inaccurate orifice meter measurements. Thus, the objective of this study was to determine the effects of swirling flow on the measurement accuracy of V-Cone meters. Specifically, the performance of 150 mm (6 inch) V-Cone meters have been evaluated at Chevron Petroleum Technology Company (CPTC) with artificially-generated swirling air flow and at Statoil's K-Lab where the swirls were generated by a series of elbows out-of-plane in high pressure (7.5 MPa) natural gas flow.

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The impact of this study lies in offshore gas metering applications[4]. On an offshore platform, a flow meter that is significantly less affected by installation effects may prove to be very beneficial. The cramped platform deck area precludes long straight pipes to condition the gas flow before being measured by the traditional orifice meters. Thus, V-Cone meters may find application on platforms if their accuracy is not compromised by short pipe lengths between the disturbances (elbows, valves, etc.) and the meter. With shorter pipes, the space and weight requirement of a metering system can be reduced which is a very important consideration for offshore platform construction and maintenance.

EXPERIMENTAL SYSTEM AND PROCEDURES

The test at CPTC was conducted in the low pressure air flow system located in Murphy Coyote Lease in La Habra, California. Figure 2 is a schematic of the experimental setup for this test. Two air blowers, each rated at 1475 SCM/H (1.25 MMSCF/D) at 103 kPa (15 psig), were used to supply the air flow. However, one of the blowers was down for this test, resulting in only half of the total flow rate capacity. A fin-fan cooler was installed downstream of the blowers to maintain compressed air temperature at approximately 3°C above the ambient temperature. A pressure control valve was placed in the bypass line to discharge the excess air from the blowers. The test section consists of flange sections for the V-cone meter, orifice meter, and a dual sonic nozzle bank. Sonic nozzles were selected as the flow reference device for the air flow system. The nozzles were calibrated near the operating conditions at the Colorado Engineering Experimental Station, Inc. (CEESI) with ±0.10% uncertainty.

For this swirling flow test, the 150 mm (6 inch) V-Cone meter was installed approximately 21 pipe diameters downstream of an axial vane swirler. The swirl generator was the same one that was used in a similar test for orifice meters.[5] Swirls of different intensities in the line could be generated easily and efficiently by turning the angle of 10 externally adjustable blades attached to the hub of the swirler. Details of the swirler construction is described in Reference 5.

At K-Lab the test was conducted in the 6" high pressure natural gas line, at the Statoil operated gas terminal at Kårstø, Norway. Figure 2A shows a schematic of the set up the test. The gas is circulated around in the closed test loop by means of a centrifugal compressor which has a maximum flowrate of 2000 ACM/H (70 000 ACF/H). The reference flowrate at K-Lab is measured by means of a series of sonic nozzles which have been calibrated in K-Lab's own primary calibration rig (Figure 2B). The swirling tests which are reported were obtained at 7.5 MPa (75 bar) and at gas temperatur of approximately 37°C.

At K-Lab the V-Cone meter was installed 100 D downstream a series of 90° elbows out-of-plane to assess the baseline performance and at 0 D, i.e. imediately at the outlet of the last elbow (Figure 2A) to look at the influence of swirls.

The manufacturer supplied three V-Cone meters of 0.65, 0.55, and 0.45 beta ratios for this evaluation.

- CPTC tested β : 0.65 - 0.55 - 0.45
- K-Lab tested β : 0.65 - 0.45

The beta ratio for V-Cone meters is defined to match the same pipe opening areas as in orifice meters. The flow rate equation follows the form for orifice meter flow calculations. However, based on gravimetric water flow calibration, the vendor supplies a meter flow coefficient to use in the V-Cone meter flow equation. The average flow coefficients supplied for the three meters were 0.843, 0.858, and 0.879, respectively. All applicable equations for V-Cone meter flow calculations are shown in Appendix A.

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RESULTS AND DISCUSSION

CPTC test

Baseline Performance

Table 1 lists the three meters' performance at the baseline condition which is taken to be swirl-free with the blade angle set at 0 degree. The reference flow rate was taken to be the sonic nozzle flow rate and the V-Cone meter deviation is defined as:

$$\% \text{ Deviation} = \frac{Q_V - Q_{SN}}{Q_{SN}} \times 100$$

where Q_V = V-Cone meter flow rate
Q_{SN} = Sonic Nozzle flow rate

The baseline performance is essentially a check on vendor's flow coefficient calibration. Except runs conducted on March 24, the observed deviations lie in the range of -0.7% to +0.8% and should be considered quite reasonable in view of uncertainties in the vendor's calibration facility, the air flow system, the expansion factor used in the flow equation, low differential pressure level, and flow distortions caused by the hub of the swirler.

Table 1 The Baseline Performance of V-Cone Meters

Run Date	Run No.	Beta Ratio	V-Cone Meter Static Pressure (kPa)	V-Cone Meter Differential Pressure (kPa)	Sonic Nozzle Flow Rate (SCMH)	V-Cone Meter Deviation from Nozzles Flow (%)
3/19/95	0	0.65	70.7	0.43	803.2	0.645
3/19/95	1	0.65	70.2	0.43	800.1	0.837
3/24/95	7	0.65	60.3	0.41	747.3	1.843
3/27/95	0	0.45	67.6	1.89	771.1	-0.719
3/28/95	0	0.45	65.2	1.86	757.8	-0.692
3/28/95	14	0.45	63.6	1.84	748.2	-0.704
3/28/95	15	0.45	64.2	1.02	544.2	-0.231
4/2/95	0	0.55	60.3	0.81	744.0	-0.645
4/2/95	11	0.55	59.6	0.81	737.1	-0.526

The vendor recommends an optimum operating differential pressure of 12.5 kPa (50 inches of water) for V-Cone meters. The recorded V-Cone meter differential pressures in this test were substantially below that level because one of the two blowers in the air flow system was out of service, resulting in only one-half of the usual throughput for the system. This low differential pressure level contributed the most uncertainty in this test. The large fluctuation in the 0.65 beta case can easily be attributed to the extremely low differential pressure (less than 0.5 kPa or 2 inches of water). Given the low flow rate, a measurement error of 24.9 Pa (0.1 inch of water) by the differential pressure transducer can cause up to 3% error in the flow rate for the β=0.65 meter, 1.5% error for the β=0.55 meter, and 0.7% for the β=0.45 meter. Thus, even a deviation of 1.8% in the β=0.65 case is still within the expected performance bound

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given the test condition.

The repeatability of the V-Cone meters is also quite good. The differences between repeated runs of same flow rate in Table 1 ranges from 0.027% for the β=0.45 meter to 0.192% for the β=0.65 meter. Again, repeatability appears to improve with higher differential pressure level.

Effects of Swirl

The swirler blades were generally set between -40 to +40 degrees to generate swirling flows of various intensities. Velocity profile surveys conducted in a previous study[6] using the same swirler have shown that the swirl generated was the solid body rotation type similar to flow passing through two close couple elbows and the observed swirl angle was close to the pre-set blade angle. In the field, swirls of 20 degrees is typically generated by double elbows and up to 40 degrees is possible when the flow exits certain header configurations. Figures 3-6 present the V-Cone meter performances at various swirl angles. There appears to be no pronounced effects of swirl intensity on V-Cone metering accuracy. The deviations generally fluctuate by less than ±0.5% from the swirl-free baseline performance. For meters of β=0.45 and β=0.55 in Figures 3-5 , there appears to be certain faint periodicity with the swirl angle, but the patterns seem to be too weak to draw firm conclusions. When the swirl angles exceed 50 degrees in Figure 6, the flow deviations then become significant. However, flows of such swirl intensity are not found in field piping systems.

This lack of swirling flow effects in V-Cone meters is in sharp contrast to orifice meters. A previous test has shown that swirls significantly depress orifice meter measurements.[6] The effects were pronounced and symmetrical as the swirler blade angles varied. Figure 7 depicts the effects of swirls on an orifice meter at β=0.5. Orifice meter undermeasured the flow rate by approximately 4% in 20° swirling flow and by about 10% in 40° swirls.

The fluid dynamics involved in the meter configuration account for the performance difference of these two meters in swirling flow. In orifice meters, the flow is forced through a hole in the center of the pipe where the vortex structure may be preserved or even enhanced due to a tighter spin imposed by the restriction. This hypothesis is supported by experimental data of more pronounced swirling flow effects in smaller beta ratio orifice meters.[7] In V-Cone meters, the flow is forced through the narrow annular space between the central cone and the pipe surface. The upstream vortices tend to be pushed toward and confined near the pipe wall region in the ensuing jet exiting the gap. The low pressure port, located at the downstream face of the cone itself, apparently is not sensitive to remaining swirls in this wake region behind a buff body.

K-Lab test

Baseline Performance

The baseline performance was assessed for 7.5 MPa respectively for beta ratios 0.65 and 0.45 and at 37°C approximately. The flowrate was varied between approximately 170 Am^3/h and 1500 Am^3/h corresponding to a max. differential pressure over the V-Cone of about 162.8 KPa (1628 10^{-3} Bar) .

Tables 2 and 4 show the performance of the 2 V-Cone (0.65 and 0.45 beta ratios) at 100 D downstream of the 90° bend. The flowrate through the V-Cone is compared to the reference flowrate through the sonic nozzles. The flowrate through the V-Cone was calculated using the C_d determined in water at low Reynolds number compared to what was obtained at K-Lab.

The deviations (%) between the V-Cone flowrates at 100D (baseline) calculated with the vendor's flow coefficient and the reference flowrate given by the sonic nozzles (SN) vary between 3% and 4%

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for $\beta = 0.65$ and $\beta = 0.45$.

The pipe Reynolds number which was obtained during the test varied from 2.10^6 to 20.10^6 which is respectively 20 times and 200 times higher than the highest Re-number obtained at CPTC.

Effect of swirls

The swirl out of the series of elbows could not be varied as during the CPTC test because the installation at K-Lab is a permanent installation which can only be modified by reconfiguration of the piping arrangement. This was not undertaken during these tests but is scheduled for later in 1995.
The influence of the disturbances introduced by the bend was assessed by comparing the deviations obtained with the 2 meters located respectively at 100D (baseline reference) and 0D which corresponds to a location immediately at the exit of the bend.

The results as plotted in figures 8 and 9 show an insignificant difference between the deviation observed at 100D and 0D and confirm the insensitivity of the V-Cone meter to the specific K-Lab flow disturbances as it was also observed during the CPTC test.

CONCLUSIONS

1. The results obtained at CPTC and K-Lab are consistent with respect to the behaviour of the V-Cone in swirling flow.

2. The installation effects of three 6" V-Cone meters of 0.45, 0.55, and 0.65 beta ratios were tested in the CPTC low pressure air flow system with swirls of various intensities generated by a 10-blade swirler. In the limited flow rate range tested, the V-cone meters performed well in terms of reference accuracy, repeatability and immunity to swirls.

3. The V-Cone meter measurements were generally within ±1% of the sonic nozzle flow reference at CPTC. Due to mechanical problems with one of the blowers in the system, the flow rate range was severely limited in this test. At differential heads much lower than their recommended operating range, V-cone meters still showed an acceptable accuracy level.

4. The installation effect was assessed for 2 V-Cones ($\beta = 0.65$ and 0.45) in K-Lab's high pressure loop. The swirl effect which was observed confirmed the results obtained at CPTC. Additional test with other upstream pipe configurations are planned.

5. The difference between the V-Cone meters and reference flowmeter at baseline conditions at K-Lab varied approximately between 3% and 4%.

6. The differences observed between V-Cone and reference flowmeters (sonic nozzles) at CPTC and K-Lab will be further investigated

7. Swirling flow seems to have little effect on V-Cone meter measurements. For swirler blade angles up to 40 degrees (at CPTC), the V-Cone meter measurements generally deviated within ±0.5% from the no-swirl baseline measurements. Above 40 degrees, V-Cone meters tend to overmeasure somewhat.

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In comparison, orifice meters are much more affected under similar swirling flow conditions with up to 10% undermeasurement at 40 degrees of swirls. At K-Lab the deviation between baseline (100D location) and the 0D location was similar to that observed at CPTC.

8. Since the accuracy of V-Cone meters are not significantly affected by swirling flow, they are better suited for applications in cramped quarters than orifice meters. The V-Cone meter should be able to measure the flow rate with reasonable accuracy with the upstream disturbances (out-of-plane elbows and/or header) located as close as 5D from the meter without any flow conditioning.

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Table 2. V-Cone No.950130 31
K-Lab. Beta:0.65 - Baseline 100D - Temp.: 37 Deg.C - Pressure:75 Bar

RUN NO.	V-CONE PRESSURE BAR	V-CONE DIF.PRESS 10-3BAR	V-CONE DENS. Kg/m3	V-Cone m3/hr Cd=0,843	S.Nozzle Ref Kg/s	S.Nozzle Ref m3/hr	Dev. %
24	78,532	1628	66,61	1638,142	29,449	1591,5127	2,930
25	78,536	1628	66,61	1638,143	29,441	1.591,269	2,946
26	78,536	1628	66,6	1638,266	29,443	1.591,602	2,932
27	77,36	1099	65,58	1362,850	24,082	1.321,891	3,099
28	77,38	1100	65,64	1362,837	24,102	1.321,913	3,096
29	77,387	1101	65,68	1363,030	24,106	1.321,291	3,159
30	76,371	625	64,5	1040,809	18,036	1.006,581	3,400
31	76,367	625	64,49	1040,889	18,035	1.006,782	3,388
32	76,353	625	64,48	1040,969	18,028	1.006,487	3,426
33	75,775	1	64,06		12,050	677,164	
34					12,044	677,131	
35					11,467	1.695,812	
36					11,461	1.697,570	
37	75,232	70	63,45	353,015	6,014	341,235	3,452
38	75,221	70	63,45	353,015	6,014	341,199	3,463
39	75,22	70	63,46	352,987	6,014	341,154	3,469
40	75,113	18	63,35	179,241	3,042	172,860	3,691
41	75,05	18	63,29	179,326	3,042	173,030	3,639
42	75,107	18	63,35	179,241	3,042	172,864	3,689

Table 3. V-Cone No. 959130 31
K-Lab. Beta:0.65 - Exit bend:0D - Temp.:37 Deg.C - Pressure: 75 Bar

RUN NO.	V-CONE PRESSURE BAR	V-CONE DIFF.PRESS 10-3BAR	V-CONE DENS. Kg/m3	V-Cone m3/hr Cd=0,843	S.Nozzle Ref Kg/s	S.Nozzle Ref m3/hr	Dev. %
85	79,163	1610	67,11	1623,441	29,4636	1580,413	2,723
86	79,143	1611	67,1	1624,045	29,458	1580,434	2,759
87	79,161	1611	67,1	1624,051	29,4659	1580,79	2,737
88	77,916	1094	65,79	1357,736	24,107	1319,085	2,930
89	77,899	1093	65,77	1357,331	24,1059	1319,527	2,865
90	77,872	1093	65,77	1357,326	24,0891	1318,627	2,935
91	76,631	622	64,86	1035,472	18,0812	1003,593	3,176
92	76,576	621	64,84	1034,804	18,0867	1004,266	3,041
93	76,611	622	64,85	1035,550	18,0932	1004,397	3,102
94	75,735	277	63,92	698,292	12,0394	670,118	2,975
95	75,725	277	63,91	698,346	12,039	670,187	2,973
96	75,724	277	63,9	698,401	12,0353	670,0348	3,004
97	75,315	70	63,49	352,904	6,0285	341,0211	3,242
98	75,325	69	63,48	350,405	6,0262	341,7391	2,536
99	75,294	69	63,43	350,543	6,022	341,7722	2,566
100	75,339	69	63,5	350,350	6,0265	341,6559	2,545
101	75,167	18	63,46	179,085	3,0513	173,107	3,454
102	75,136	18	63,44	179,114	3,0505	173,1059	3,470
103	75,107	18	63,4	179,170	3,0495	173,1511	3,476

Table 4. V-Cone No. 950130 33
K-Lab. Beta:0.45 - Baseline 100D - Temp.:37 Deg. C - Pressure: 75 Bar

RUN NO.	V-CONE PRESSURE BAR	V-CONE DIFF.PRESS 10-3BAR	V-CONE DENS. Kg/m3	V-Cone m3/hr Cd=0,879	S.Nozzle Ref Kg/s	S.Nozzle Ref m3/hr	Dev. %
21	82,154	6765	70,4	1450,764	27,1692	1389,3271	4,422
22	82,156	6765	70,39	1450,868	27,2655	1389,3353	4,429
23	82,16	6766	70,39	1450,968	27,1653	1389,3992	4,431
24	80,627	5321	68,98	1313,205	24,1147	1258,6029	4,338
25	80,64	5321	69,02	1312,833	24,1254	1258,3644	4,329
26	80,638	5322	69,04	1312,755	24,1255	1258,0256	4,350
27	78,15	2977	66,63	1016,642	18,071	976,4239	4,119
28	78,174	2979	66,68	1016,593	18,0864	976,536	4,102
29	78,163	2978	66,68	1016,427	18,0882	976,5993	4,078
30	76,466	1317	64,73	694,644	12,0313	669,1257	3,814
31	76,47	1317	64,74	694,591	12,0343	669,1884	3,796
32	76,472	1317	64,74	694,591	12,0358	669,2361	3,789
33	75,423	328	63,67	352,186	6,0139	340,0228	3,577
34	75,436	328	63,64	352,269	6,0139	340,2056	3,546
35	75,44	328	63,64	352,270	6,0128	340,117	3,573
36	75,168	83	63,34	177,960	3,0367	172,5937	3,109
37	75,164	84	63,35	179,014	3,0354	172,4832	3,786
38	75,124	83	63,33	177,974	3,034	172,4657	3,194

Table 5. V-Cone No. 950130 33
K-Lab. Beta:0.45 - Exit bend:0D - Temp.: 37 Deg. C - Pressure: 75 Bar

RUN NO.	V-CONE PRESSURE BAR	V-CONE DIF.PRESS 10-3BAR	V-CONE DENS. Kg/m3	V-Cone m3/hr Cd=0,879	S.Nozzle Ref Kg/s	S.Nozzle Ref m3/hr	Dev. %
39	82,688	6693	70,75	1440,724	27,1841	1383,1688	4,161
40	82,67	6691	70,73	1440,719	27,1755	1383,2223	4,157
41	82,666	6695	70,72	1441,204	27,1824	1383,6428	4,160
42	82,206	5359	70,07	1308,249	24,4639	1256,8236	4,092
43	81,058	5278	68,95	1308,889	24,0862	1257,6631	4,073
44	81,016	5275	68,92	1308,804	24,1008	1258,8271	3,970
45	81,051	5275	69,15	1306,648	24,1199	1255,6577	4,061
46	81,058	5280	69,19	1306,844	24,133	1255,6953	4,073
47	78,494	2964	66,65	1014,471	18,0896	977,077	3,827
48	78,471	2963	66,67	1014,148	18,1006	977,3586	3,764
49	78,472	2964	66,68	1014,236	18,1024	977,356	3,773
50	76,631	1325	64,78	696,454	12,0607	670,2808	3,905
51	76,624	1314	64,68	694,151	12,0535	670,8699	3,470
52	76,62	1324	64,68	696,734	12,0565	671,0342	3,830
53	75,401	326	63,71	351,006	6,03	340,7375	3,014
54	75,421	327	63,72	351,514	6,033	340,8244	3,136
55	75,414	327	63,73	351,486	6,0325	340,7623	3,147
56	75,155	83	63,46	177,792	3,0491	172,964	2,791
57	75,135	83	63,45	177,806	3,0484	172,9533	2,806
58	75,154	83	63,45	177,806	3,0484	172,9474	2,809

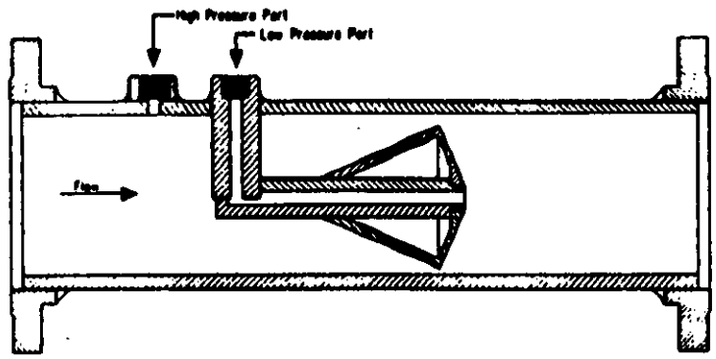


Figure 1
Cutaway Drawing of V-Cone Differential Pressure Flowmeter

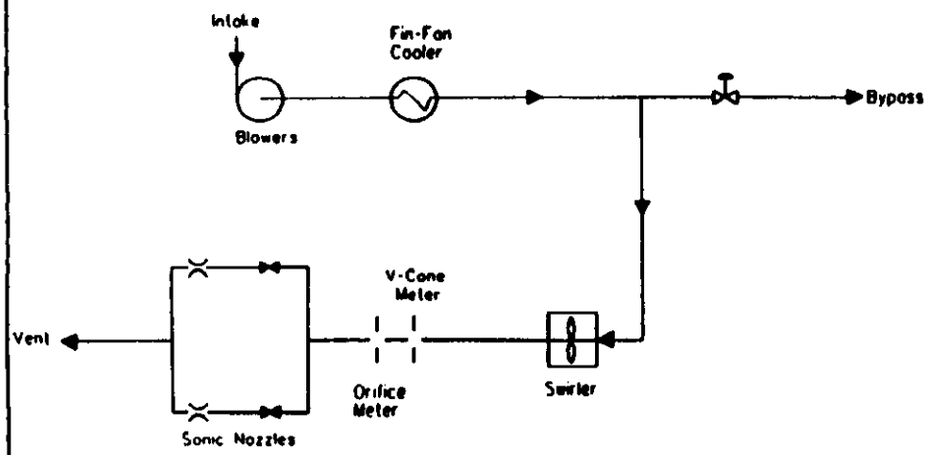
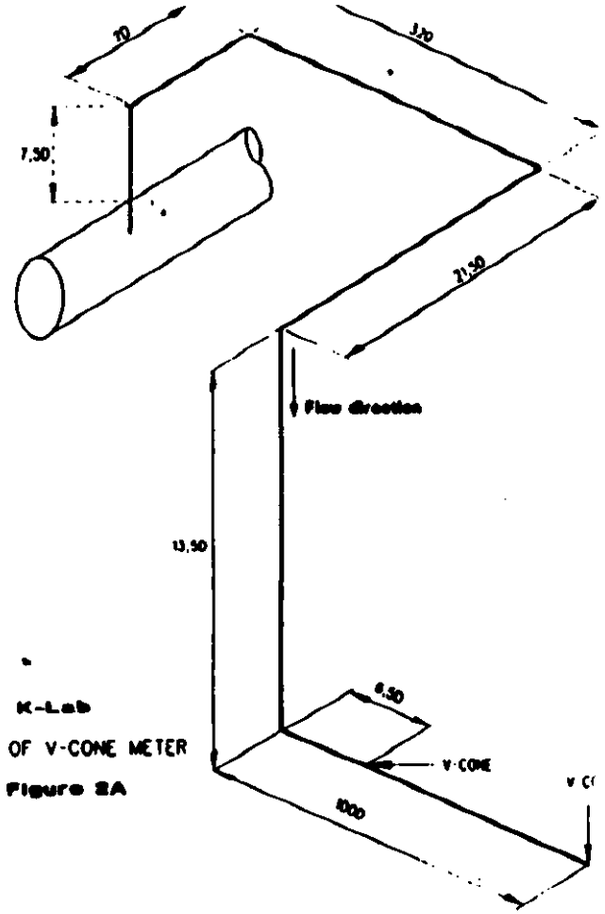


Figure 2
Schematic of Air Flow System in La Habra, CA



K-Lab
TEST OF V-CONE METER
Figure 2A

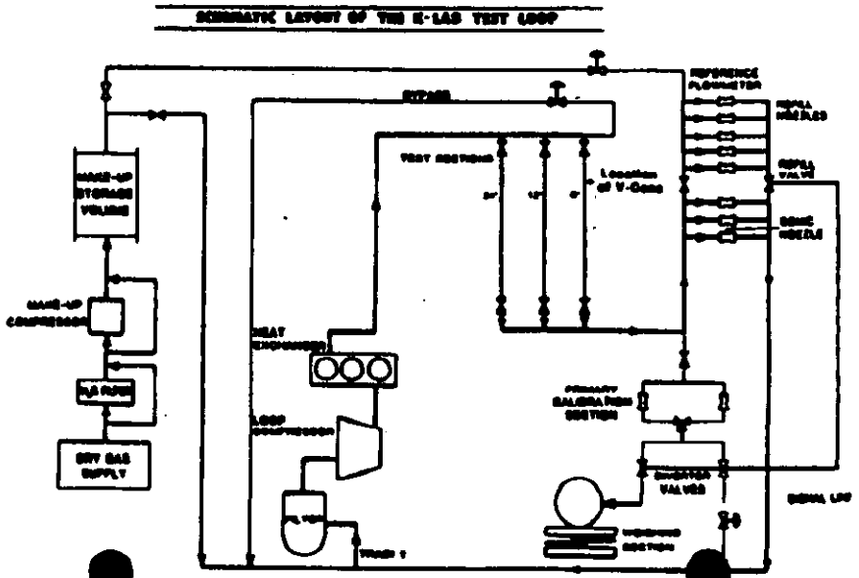


Figure 2B

EFFECT OF SWIRL ANGLE ON V-CONE METER (β=0.45) FLOW MEASUREMENT

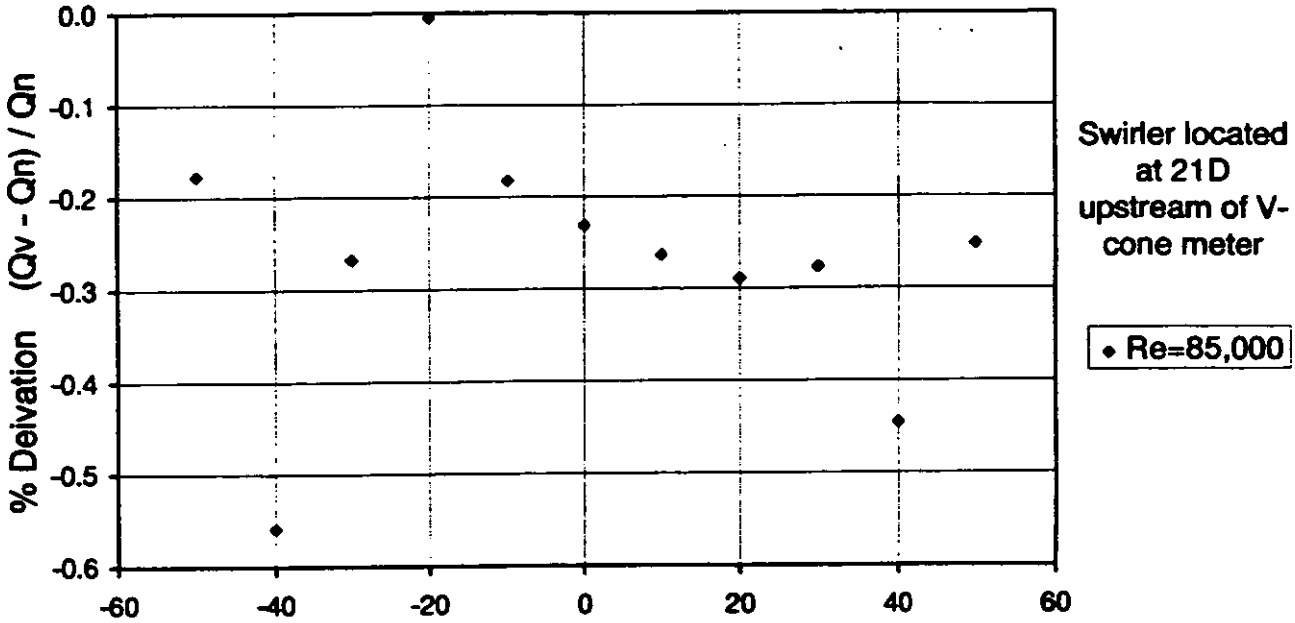


Figure 3 Swirler Blade Angle (degree)

V_SW45A.XLS

9/14/95

EFFECT OF SWIRL ANGLE ON V-CONE METER (β=0.45) FLOW MEASUREMENT

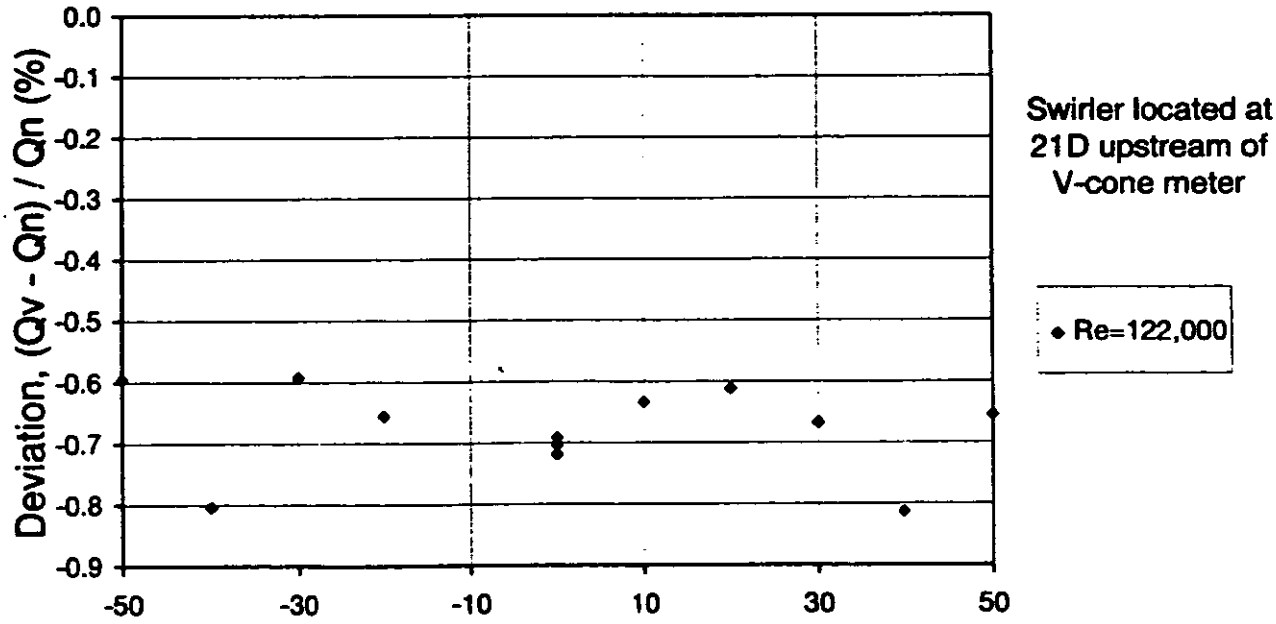


Figure 4 Swirler Blade Angle (degree)

EFFECT OF SWIRL ANGLE ON V-CONE METER (β=0.55) FLOW MEASUREMENT

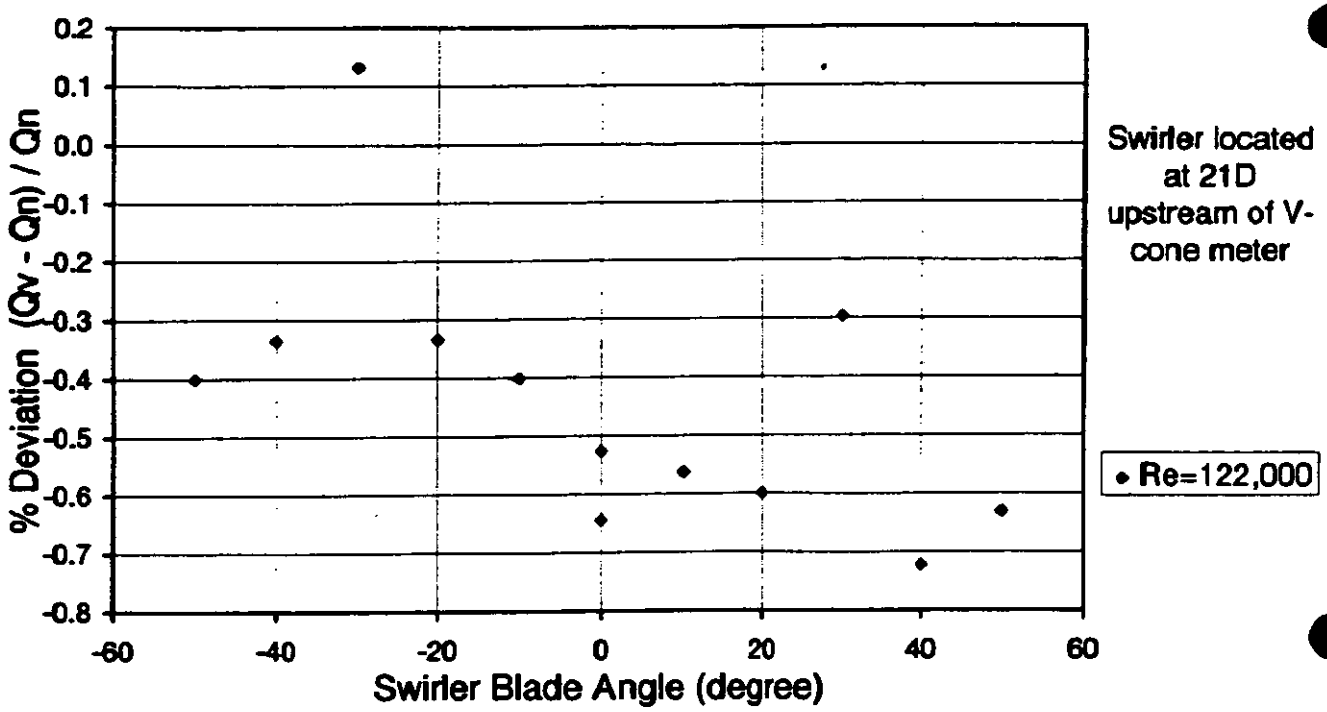


Figure 5

V_SW55.XLS

JJSS 9/14/95

EFFECT OF SWIRLING FLOW ON V-CONE METER (β=0.65) FLOW MEASUREMENT

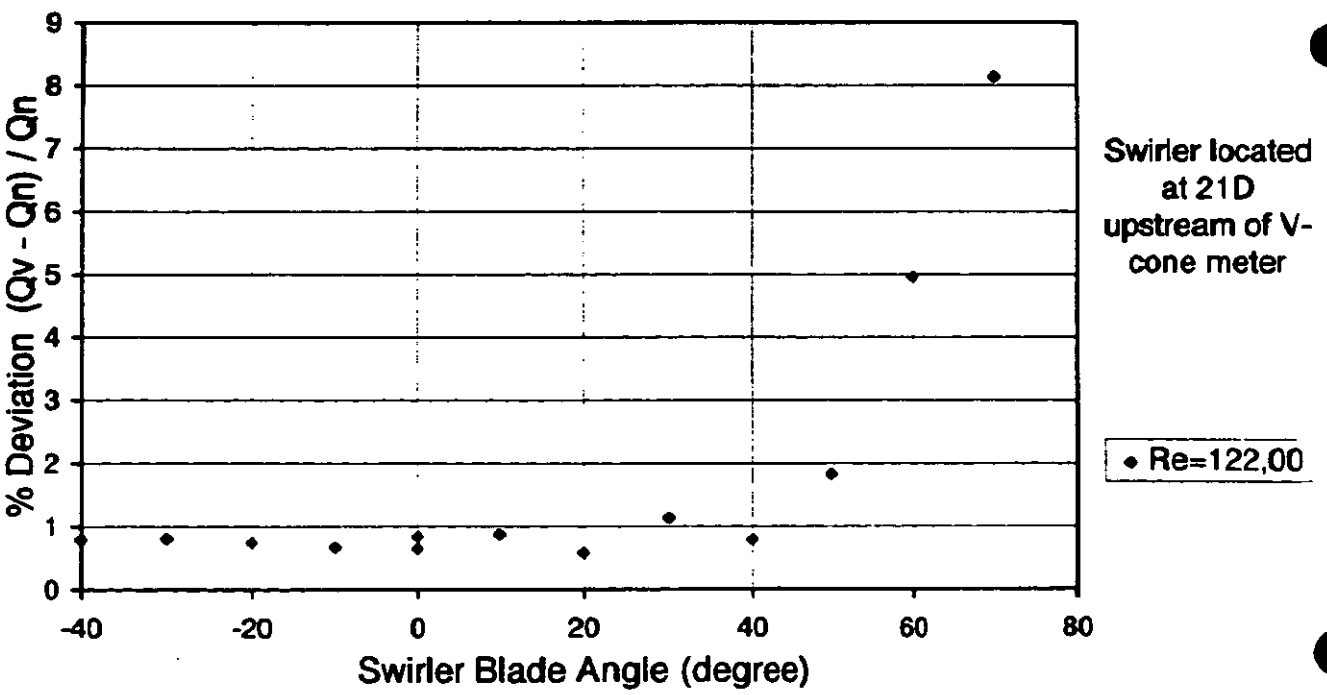
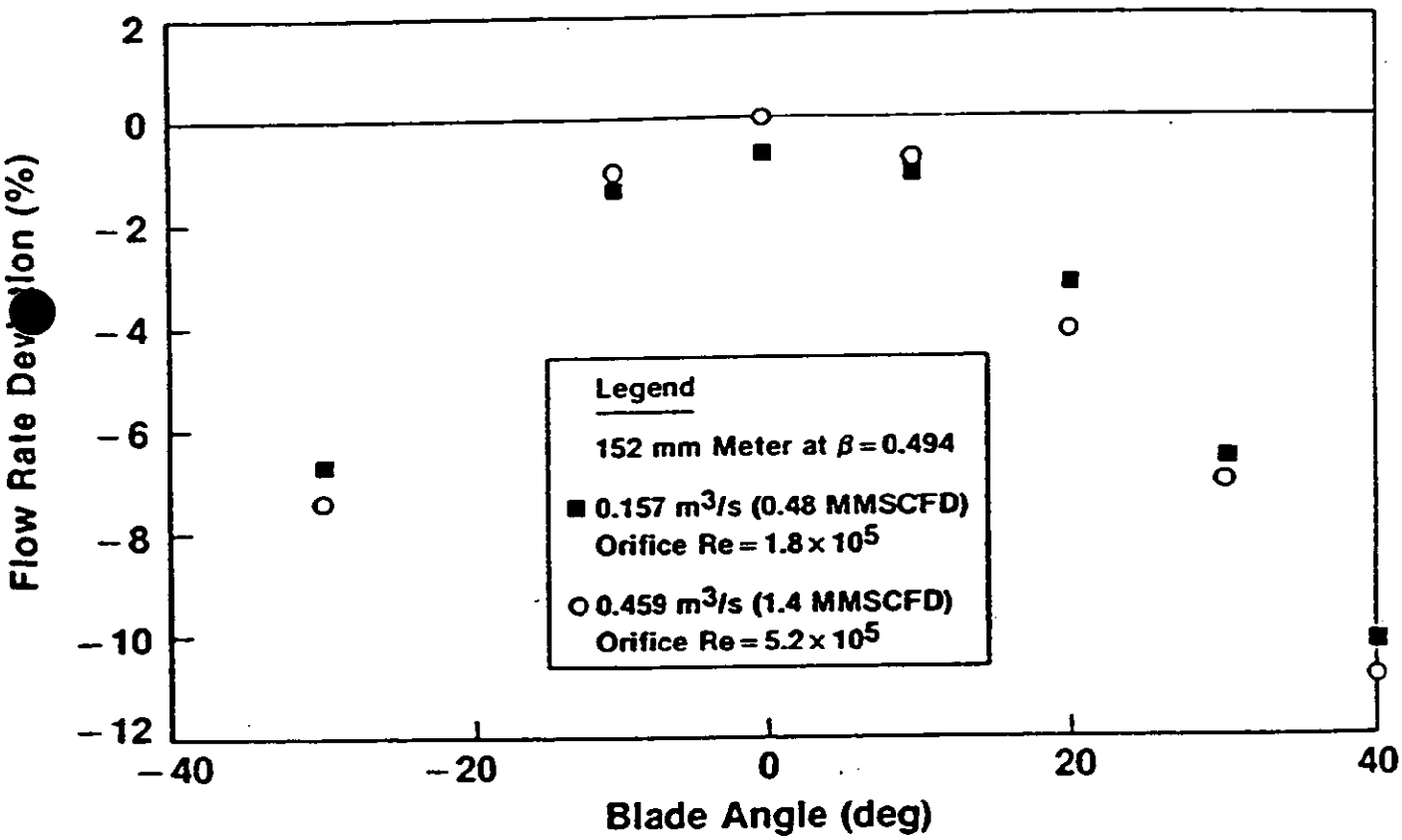


Figure 6

V_SW65.XLS



Effect of Flow Rate on Orifice Metering ($\beta = 0.494$) in Swirling Flows

Figure 7

LE 89–0102

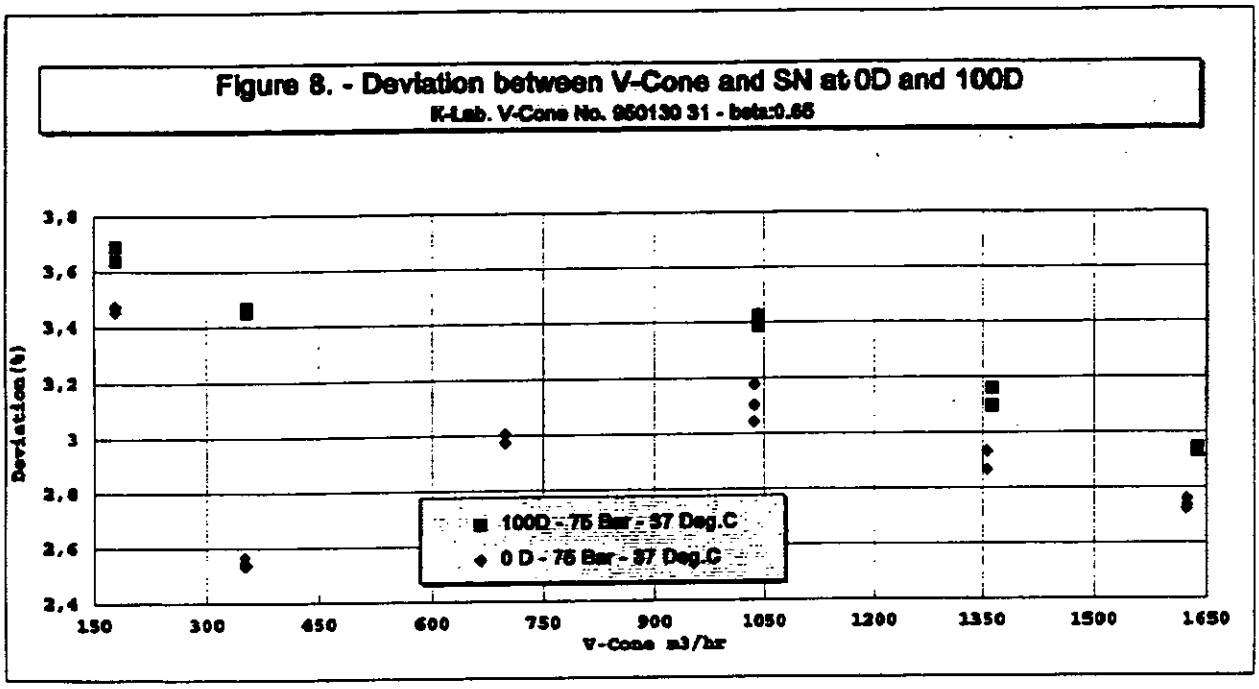


Figure 8. - Deviation between V-Cone and SN at 0D and 100D
K-Lab. V-Cone No. 950130 31 - beta:0.65
Deviation (%)
3,8
3,6
3,4
3,2
3
2,8
2,6
2,4
150
300
450
600
750
900
1050
1200
1350
1500
1650
V-Cone m3/hr
100D - 75 Bar - 37 Deg.C
0 D - 75 Bar - 37 Deg.C

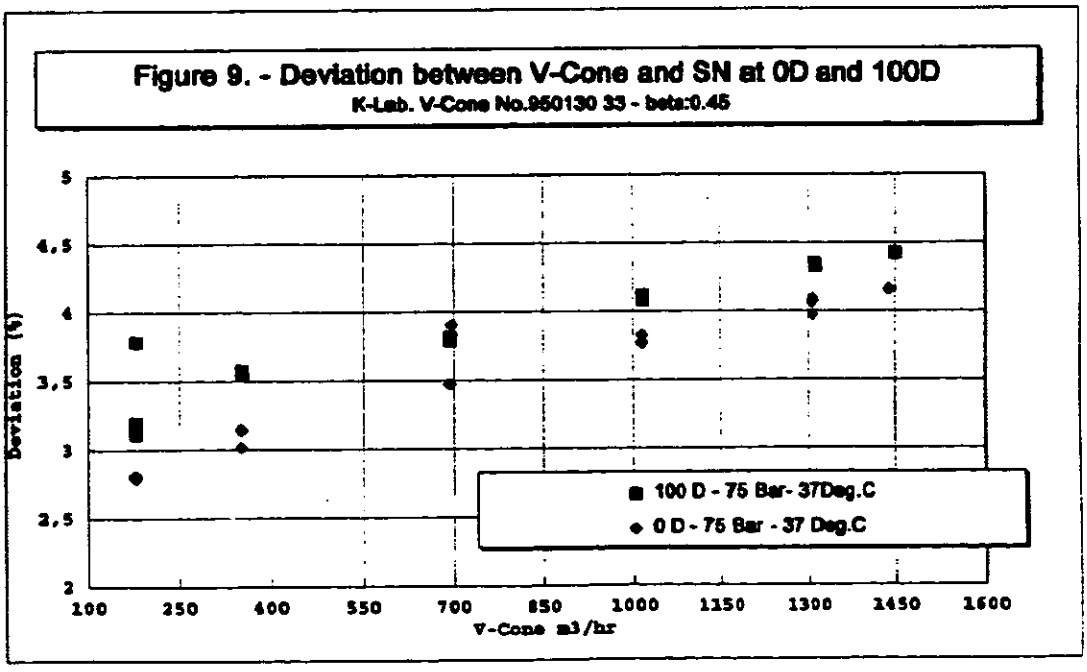


Figure 9. - Deviation between V-Cone and SN at 0D and 100D
K-Lab. V-Cone No.950130 33 - beta:0.45
Deviation (%)
5
4,5
4
3,5
3
2,5
2
100
250
400
550
700
850
1000
1150
1300
1450
1600
V-Cone m3/hr
100 D - 75 Bar- 37Deg.C
0 D - 75 Bar - 37 Deg.C

McCROMETER

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APPENDIX A

V-Cone Equation of Flow

Flow equation:

$$Q = \frac{\pi}{4}\sqrt{\frac{2g_c}{\rho}}\,\frac{D^2\beta^2}{\sqrt{1-\beta^4}}\,\sqrt{\Delta P}\;C_f\,Y$$

Beta equation:

$$\beta = \sqrt{1-\frac{d^2}{D^2}}$$

Gas expansion factor:

$$R = 1-\left(\frac{\Delta P}{P_L}\right)$$

$$Y = \sqrt{\frac{\left(\left(1-\beta^4\right)\left(1-R^{\frac{k-1}{k}}\right)\times\frac{k}{k-1}\times R^{\frac{2}{k}}\right)}{\left(1-\left[\beta^4\times R^{\frac{2}{k}}\right]\times(1-R)\right)}}$$

Nomenclature

β	meter beta ratio, dimensionless
C_f	flow coefficient of the meter, dimensionless
d	cone outside diameter, in meter
D	meter inside diameter, in meter
ΔP	differential pressure, in Pa or kg/ms^2
g_c	conversion constant (g_c = (1 lb_m) (32.174 ft^2/s^2) / (1 lb_f) kgm/Ns^2) = 0.45359 (kg). 32.174 *0.3048(m/s^2)/4.4482 kgm/s^2). For all practical purpose g_c = 1 when SI units are applied.
k	fluid isentropic exponent at flowing conditions,dimensionless
P_L	absolute static line pressure, in Pa or kg/ms^2 at the meter
Q	gas flowrate,in actual m^3/sec
Y	gas expansion factor for contoured elements, dimensionless
ρ	flowing fluid density in kg/m^3

(*) Chevron Petroleum Technology Company, 1300 Beach Bd., La Habra, CA 90631-6374
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Main Index

North Sea FLOW Measurement Workshop 1995

Paper 22:

PERFORMANCE TEST OF A 6 PATH USM

5·5

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Organiser:
Norwegian Society of Chartered Engineers
Norwegian Society for Oil and Gas Measurement
Co-organiser:
National Engineering Laboratory, UK

PERFORMANCE TESTS OF A 6-PATH USM

by
Asle Lygre (CMR[1]), Eivind Dykesteen (Fluenta[2])
Atle A. Johannessen (CMR) and Rune Norheim (Fluenta)

ABSTRACT

A new 6-path ultrasonic gas flow meter has been developed. A 300 mm (12") version of the meter has been tested at Statoil's calibration facility K-Lab, in Norway and the test results are presented. Tests have been carried out at ideal conditions over the velocity range 0.4 to 9 m/s at pressures between 20 and 100 bar. Installation tests 10D and 5D downstream of a double S-bend (four 90° bend in the same plane) were also carried out. At ideal conditions the deviation lies within ±0.5% for all pressures between 20 and 100 bar over the velocity range 0.4 to 9 m/s at 37 °C. The deviation lies within ±0.7% at 5D and 10D over the velocity range 0.4 to 9 m/s at 37 °C and 60 bar.

INTRODUCTION

This paper presents the tests results of a new 6-path ultrasonic gas flow meter. The new meter represents a further development of the 5-path FMU 700 [1]. Based on the test results of the 5-path meter, Christian Michelsen Research in cooperation with Fluenta, developed an improved meter in the period 1993-95. The meter has been tested at K-Lab (Statoil, Norway), Lintorf (Ruhrgas, Germany) and Westerbork (Gasunie, the Netherlands). Only the tests at K-Lab are reported here, and the results from the other tests will be published later.

THE ULTRASONIC METER

In the following a brief description of the major modifications of the 5-path version described in [1] will be given. For a more general description of the flow meter technology and the capabilities of multi-path meters, we refer to [1].

The 6-path configuration

The tests of the 5-path version revealed that this meter was robust in swirling flow, e.g. generated by a double bend out of plane, whilst sensitive to cross flow encountered downstream of a single 90° bend. Examples of simple swirl and cross flow patterns are shown in Fig. 1a and 1b, respectively. When designing the 5-path meter, it was decided to apply a configuration which was robust to swirling flow. However, it turned out that the meter performance in cross flow was not acceptable for this meter, and the meter performance was also sensitive to the orientation of the acoustic paths relative to the bend.

Referring to Fig.1a it can be seen that when the acoustic paths in the upper and lower part of the pipe, are confined to the same plane, the flow velocity component along the two acoustic paths have opposite signs in swirling flow. If the swirl flow is symmetrical, perfect cancellation of the non axial flow components will occur. On the other hand, if the path configuration shown in Fig.1a is exposed to cross flow as shown in Fig.1b, the flow velocity components along the two acoustic paths will not cancel. This in fact, explains the characteristics of the performance of the 5-path configuration in swirling and cross flow situations.

Referring to Fig.1b it can be seen that when the acoustic paths in the upper and lower part of the pipe, are confined to planes which are perpendicular to each other, the flow velocity component along the two acoustic paths have opposite signs in a cross flow situation. If the cross flow is symmetrical, perfect cancellation of the non axial flow components will occur.

In the new 6-path configuration the features of the two configurations in Fig.1a and 1b are partly combined. This is carried out as illustrated in Fig.2 where the two paths in the upper part of the pipe are "doubled". In this way the non-axial flow components in the upper part of the plane (pipe) can in fact be measured. If the secondary flow pattern is symmetrical, perfect cancellation of the non axial flow components will result. This allows the meter to handle both cross flow and swirling flow.

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It should be emphasized that the above analysis is very simplified and is merely included to illustrate the basic principles.

The flow computer

A new and more compact flow computer has been designed. The new computer features a non-volatile disk for storage of executable software codes and parameters for calculation of fiscal quantities. Further, the computer contains a clock with fiscal accuracy in accordance with [2]. In addition to volumetric flow rate, the computer can therefore calculate and store accumulated gas volumes. The computer supports smart transmitters based on the HART protocol, and information can be exchanged with the main data acquisition system through the Modbus protocol. Density input can also be given as a frequency signal. Mass flow rate, or accumulated mass, can accordingly be calculated according to fiscal standards. The SONFLOW software package, providing standard gas conversion codes like AGA8-85 and ISO 6976 are also implemented in the computer allowing conversion of e.g. measured volumetric flow rate to standard conditions [3].

Electronics and ultrasonic transducers

Both the electronics and the transducers of the meter have been redesigned in order to improve the reliability and stability of the meter. An important objective of the redesign has been to be able to replace transducers and/or electronics without having to repeat the zero calibration of the meter, see below. As yet, this feature has not been experimentally verified. A tool that enables replacement of the transducers without depressurizing the pipe line, has been designed. In this case the transducers will be mounted to the spool piece through double block and bleed ball valves.

Zero calibration

Prior to the calibration tests, the meter was zero calibrated at conditions close to the line conditions. All the geometrical constants were carefully measured; i.e. the angles of each transducer pair relative to a plane containing the pipe axis, the distances between the transducers in each pair and the internal diameter of the flow meter spool. All distances were measured with an uncertainty of 0.05 mm and the angles were measured with an uncertainty of 0.1 degrees.

The flow meter spool was pressurized using nitrogen and submersed in a temperature controlled bath. All transit time delays, i.e. Δt-corrections and delays of the absolute transit times, were measured at 37 °C for the pressures 20, 40, 60, 80 and 100 bar. Average transit time delays for the pressure range 20 to 100 bars were calculated and loaded in the flow computer. The same calibration parameters were used over the pressure range 20 to 100 bar. During the tests at K-Lab no other calibration constants than the zero calibration parameters established prior to the tests, were applied. The transit time delay in the cables between the CPU-unit and the meter spool is automatically accounted for, and thus the zero calibration can be carried out with a short pair of signal cables which are easy to handle.

TEST RESULTS

Test conditions

At K-Lab a bank of sonic nozzles constitutes the reference measurement system. The sonic nozzles are primary calibrated against a weighing tank. Pressure and temperature are measured in the test section close to the meter under test, and the volumetric flow rate measured by the ultrasonic meter is converted to mass flow by calculating the density using the AGA8-85 equation. The measured mass flow is then compared to the reference mass flow measured by the sonic nozzles, and the % deviation is calculated.

The tests were conducted at ideal conditions with 65D straight run of pipe upstream of the meter and with a double S-bend (four single bends in the same plane) 10 and 5D upstream of the meter. The meter was tested over the flow range 0.4 to 9 m/s at pressures between 20 and 100 bar. At K-Lab 9 m/s is the maximum velocity for a 12" meter. The cable length between the flow meter spool and the flow computer was approximately 215 m. The temperature of the surroundings varied between 10 and 25 °C in the test period. The typical gas composition of the dry natural gas at K-Lab was 82.6% (CH_4), 14% (C_2H_6), 1.1% (C_3H_8), 0.04% (iC_4H_{10}), 0.06% (nC_4H_{10}) , 0.006% (C_5+), 0.8% (CO_2) and 1.3% (N_2). The tests were carried out in the period 24th of April to 23rd of June 1995.

Ideal conditions

In Fig. 3 the test results at ideal conditions are displayed. The deviation lies within ±0.5% for all pressures between 20 and 100 bar over the velocity range 0.4 to 9 m/s at 37 °C.

Keeping the flow rate and temperature constant, and varying the pressure between 20 and 100 bar results in a maximum shift of 0.5% of the deviation curve. There appears to be no systematic pressure effect e.g. in the sense constantly decreasing deviation with decreasing/increasing pressure.

The linearity over the velocity range 0.4 to 9 m/s , at constant pressure and temperature, is less than ±0.4%. In the range 1 to 9 m/s the linearity is less than ±0.3%.

The repeatability, keeping pressure, temperature and flow rate constant, appears to be of the order 0.05% over the velocity range 1 to 9 m/s.

The reproducibility of the meter was tested by repeating the flow calibration at ideal conditions (60 bar and 37°C) after a period of 7 weeks. During this period the meter was pressurized and depressurized several times and various installation tests were carried out. Over the velocity range 0.4 to 9 m/s the shift in the deviation curve was 0.25% or less, see Fig.4. No meter parts, i.e. electronics or transducers, were exchanged during this period, and the zero calibration parameters were unaltered.

Installation effects

The meter was installed 10D downstream of a double S-bend (four 90° bends lying in the same plane) and tests were carried out at three orientations of the meter; 0°, 90° clockwise (CW) and 90° counter clockwise (CCW). At the 0° orientation, the acoustic paths of the meter are perpendicular to the vertical bend plane, and at the 90° CW(CCW) the paths are lying in the bend plane. Tests were also conducted at 5D at the 0° orientation. All the tests were carried out at 60 bar over the velocity range 0.4 to 9 m/s. The deviation curves are displayed in Fig.5.

The deviation lies within ±0.7% at 5D and 10D over the velocity range 0.4 to 9 m/s at 37 °C and 60 bar.

Compared to the deviation curve at ideal conditions at 60 bar and 37 °C, the shift is maximum -0.5% and +0.7% when the meter is installed 10D downstream of the double S-bend depending on the orientation of the meter. The linearity is not affected by installing the meter 10D from the bend. At 5D and 0° orientation, the shift is maximum +0.6%, and the linearity is also increased compared to ideal conditions.

Fig. 6 shows the mean velocity and the speed of sound at 10D, 60 bar and 37 °C when the flow in the loop is reduced from 7 to 3 m/s. The step wise response of the meter to the reduced flow rate is easily depicted and the corresponding temperature effect is clearly seen as an oscillation in the speed of sound. From the measured speed of sound it is observed that stable conditions in the rig are achieved some 10 mins. after the flow rate reduction.

CONCLUSIONS

At ideal conditions the deviation lies within ±0.5%, without any flow calibration of the meter, for all pressures between 20 and 100 bar over the velocity range 0.4 to 9 m/s at 37 °C. The meter was zero calibrated prior to the installation at K-Lab, and the results indicate that a flow calibration is not necessary when the meter operates in fully developed flow.

The linearity is less than ±0.3% and the repeatability is of the order 0.05% over the velocity range 1 to 9m/s.

The meter was installed 10D and 5D downstream of a double S-bend (four single 90° bends in the same plane). The deviation lies within ±0.7% for all meter orientations (0°) at 5D and (0°, 90°CW and 90°CCW) 10D over the velocity range 0.4 to 9 m/s at 37 °C and 60 bar.

ACKNOWLEDGMENTS

The authors greatly acknowledge the support from Statoil, Norsk Hydro, Phillips Petroleum, BP and the Research Council of Norway (the KAPOF program) in the development of the new 6-path meter.

Likewise the authors highly appreciate the work of the project teams at CMR and Fluenta consisting of Per Lunde, Reidar Bø, Morten Andersen, Kjell-Eivind Frøysa, Ørjan Villanger, Hans Ingebrigtsen, Gunnar Wedvich, Svein Værholm and Sigmund Hjerman.

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[1] Lygre A., Folkestad T., Sakariassen R. and Aldal D. : "A new multi-path ultrasonic flow meter for gas", 10th North Sea Flow Measurement Workshop, organized by NEL, Glasgow, at Peebles Hotel Hydro, Scotland, 27-29 October 1992. CMR report no. CMR-92-A10005.

[2] Norwegian Petroleum Directorate: "Regulations relating to fiscal measurement of oil and gas", 1995, ISBN 82-7257-437-3.

[3] Institutt for Energiteknikk, K-Lab: Sales brochure, SONFLOW. IFE, Kjeller, Norway. K-lab, P.O. 308, N-5508 Haugesund, Norway.

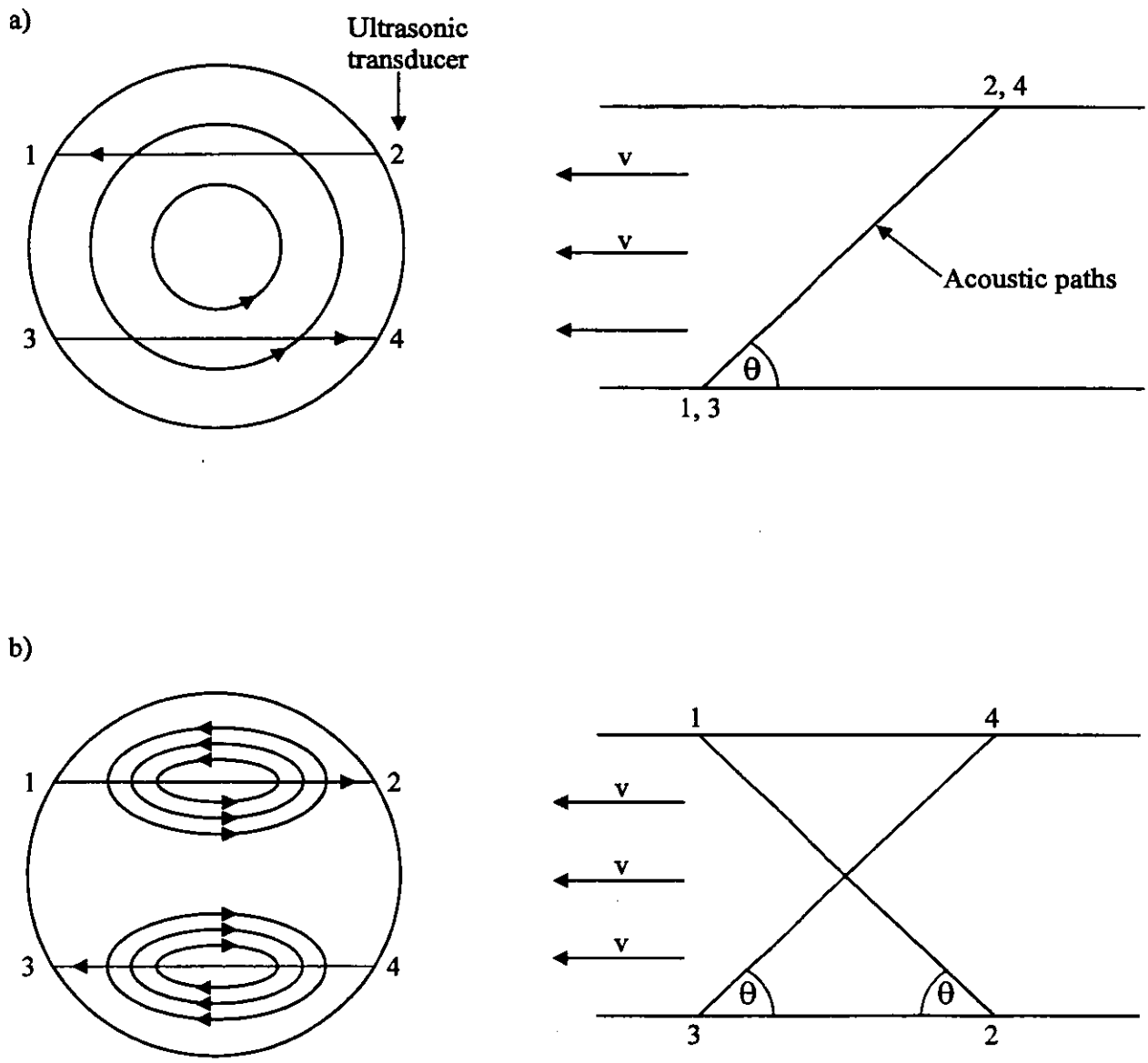

Fig. 1 **a)** Swirling flow. The flow component along path (3-4) is $v\cos\theta - v_s$, and along path (1-2) $v\cos\theta + v_s$. Accordingly cancellation is achieved when integrating (summing) the measured velocities to calculate the volumetric flow rate. v_s is the component of the secondary flow along the acoustic path. **b)** Cross flow. The flow component along path (3-4) is $v\cos\theta + v_s$, and along path (1-2) $v\cos\theta - v_s$. Accordingly cancellation is achieved when integrating (summing) the measured velocities to calculate the volumetric flow rate. v_s is the component of the secondary flow along the acoustic path.

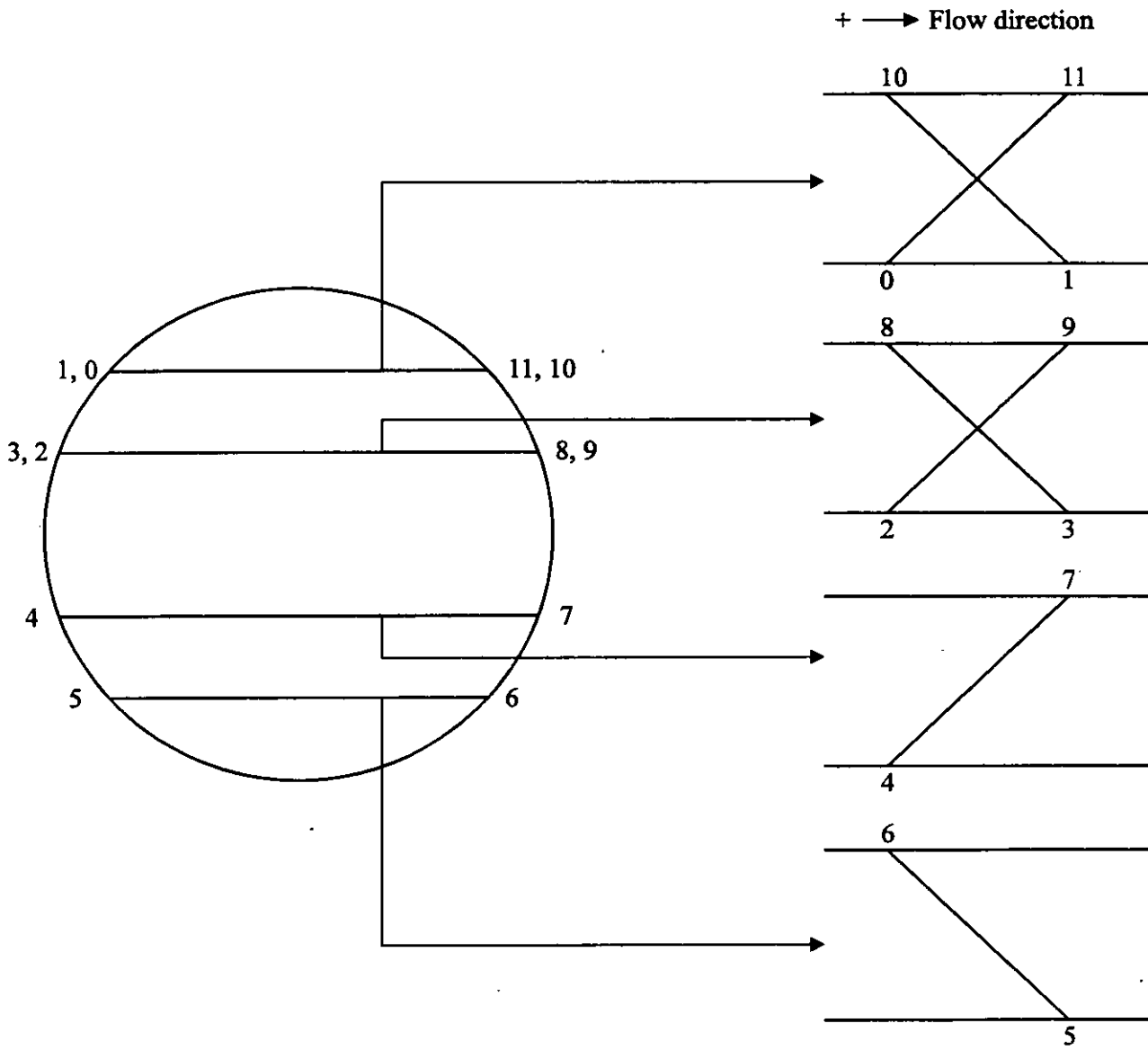

Fig. 2 The configuration of the 6 acoustic paths in the FMU 700.

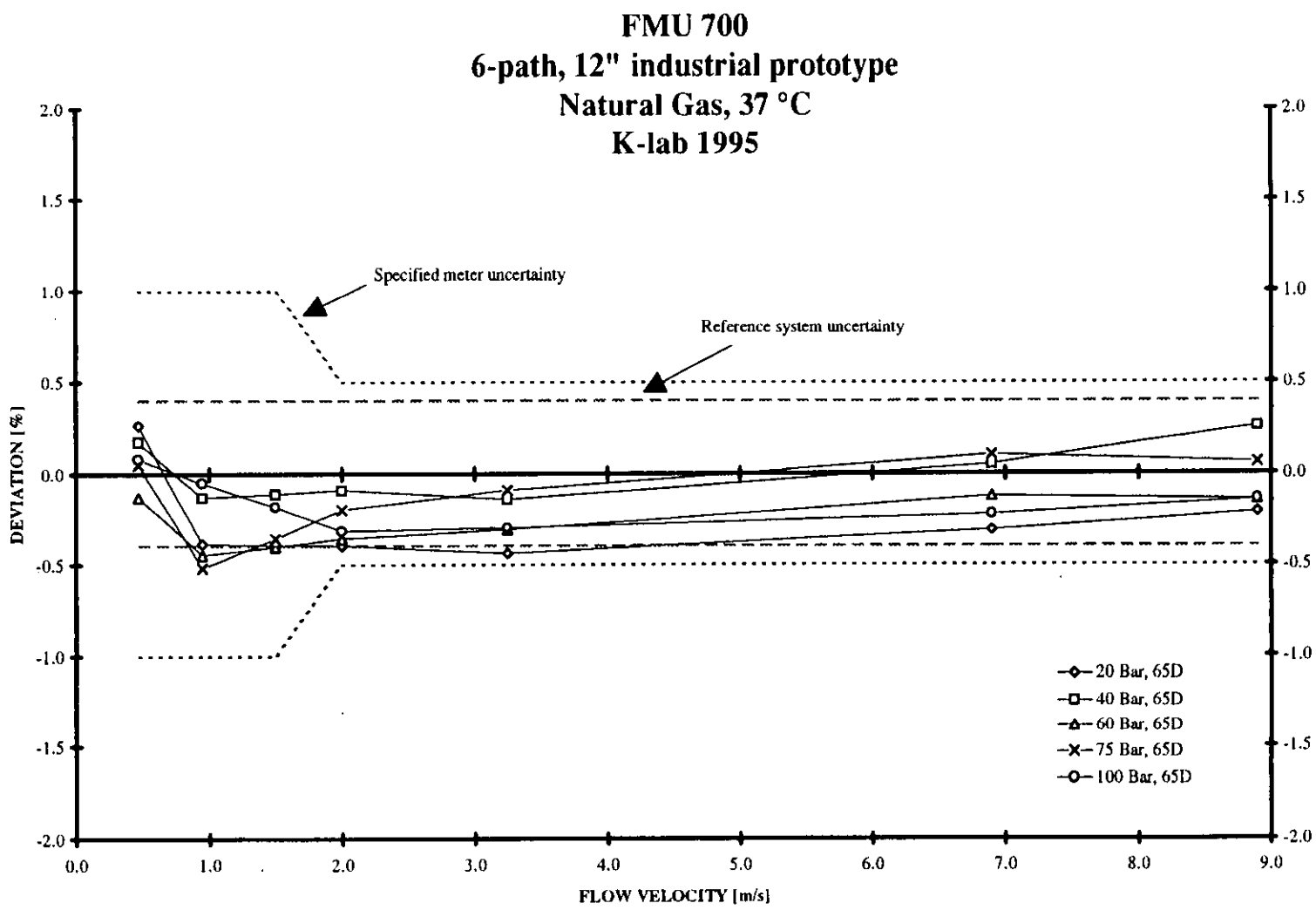

Fig. 3 Observed deviation at ideal conditions at K-Lab with 65D straight inlet length upstream of the 6 path ultrasonic flow meter. The tests were carried out at 37 °C for pressures in the range 20 to 100 bar over the velocity rang 0.4 to 9 m/s. Each mark on the curves represents the average deviation of 2 to 5 consecutive measurements averaged over 300 seconds.

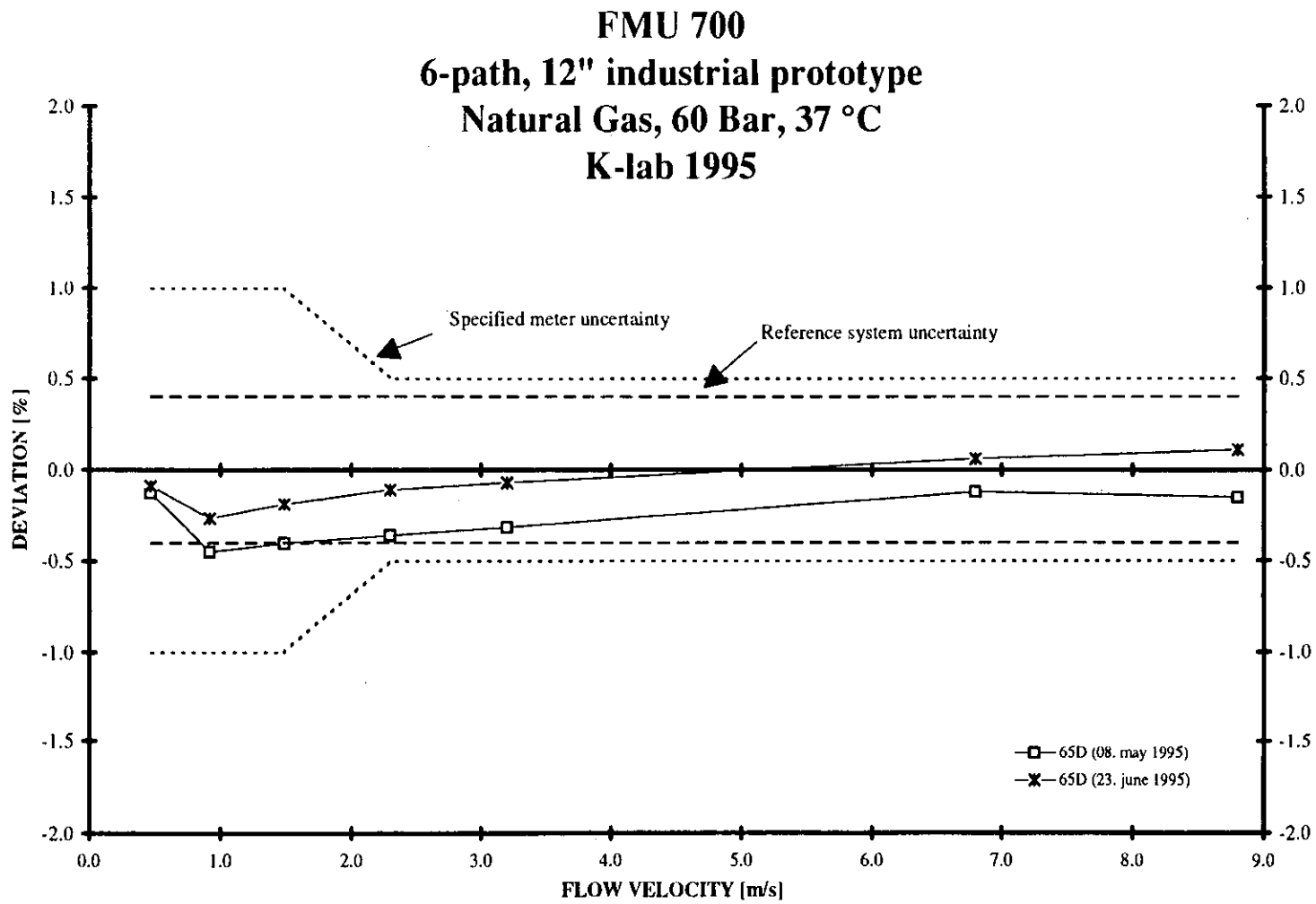

Fig. 4 Reproducibility test of the 6 path ultrasonic flow meter. Two tests at ideal conditions at 60 bar and 37 °C were carried out. The tests were spaced 7 weeks in time.

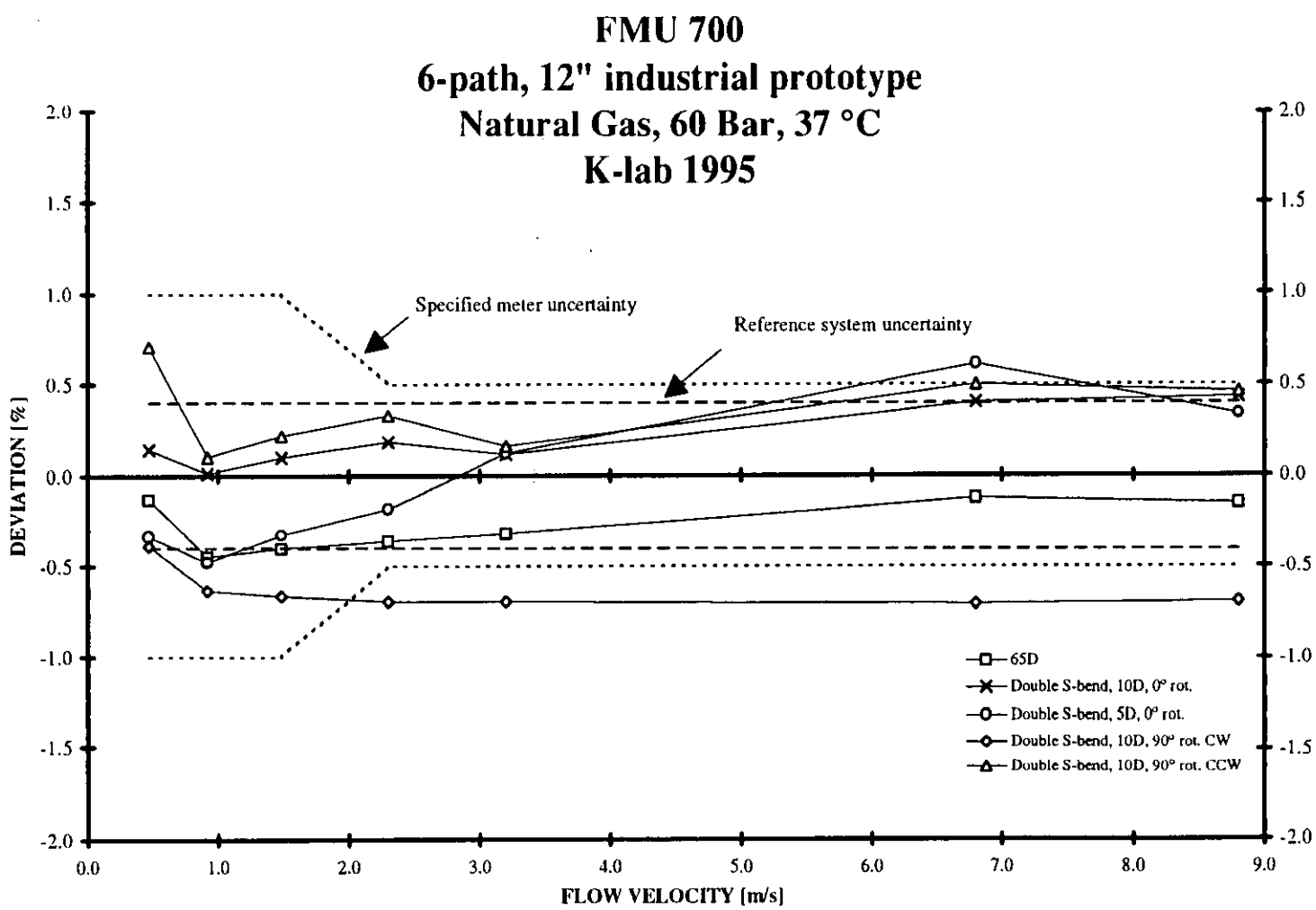

Fig. 5 Observed deviation 5 and 10D downstream of a vertical double S-bend in the same plane (four bends in the same plane). At the 0° orientation, the acoustic paths are horizontal, i.e. perpendicular to the bend plane. At the 90° CW and CCW orientations, the acoustic paths are confined to the bend plane. The tests were carried out at 60 bar and 37 °C. Each mark on the curves represents the average deviation of 2 to 5 consecutive measurements averaged over 300 seconds.

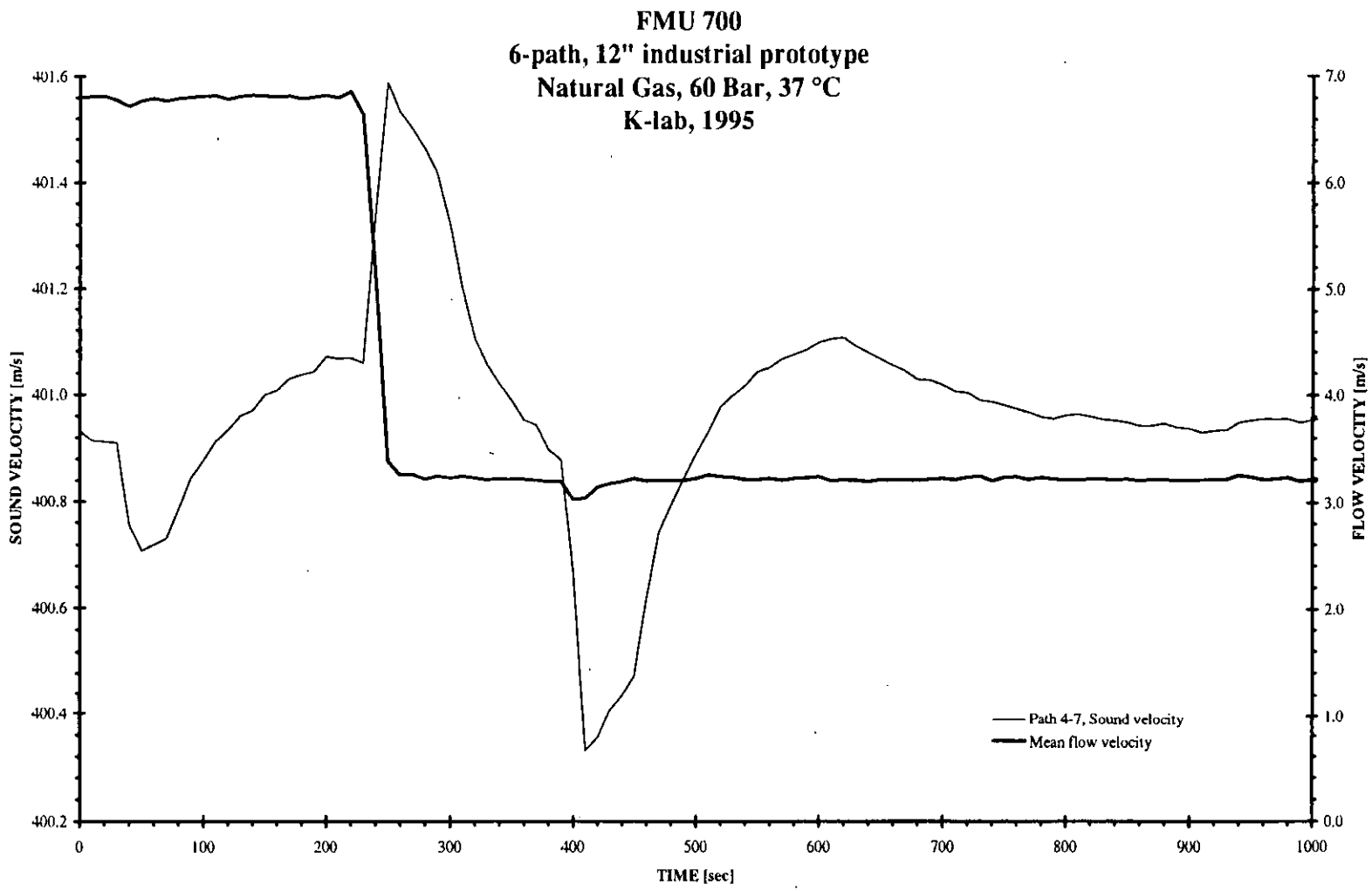

Fig. 6 Response of the 6 path ultrasonic flow meter when the flow was reduced from 7 to 3 m/s at K-Lab. The test was carried out at 60 bar and 37 °C when the meter was installed 10D downstream of the double S-bend.

Main Index

North Sea FLOW Measurement Workshop 1995

Paper 24:

TURBINE METERS FOR VERY HIGH PRESSURE -A NEW LOOK AT AN OLD CONCEPT

5·6

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TURBINE METERS FOR VERY HIGH PRESSURE - A NEW LOOK AT AN OLD CONCEPT

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SUMMARY
Turbine meter design was originally limited by the requirement for calibration with atmospheric air. These limitations on the design are shown to be in conflict with performance at high pressure operating conditions. Calibration facilities operating at high pressure are now available and eliminate the need to design a meter that also passes low pressure calibration tests. The improvements by designing for high pressure only are highlighted and illustrated with test results.

The recent developments to eliminate installation effects are explained and illustrated with data on the results obtained.

Several systems to monitor performance of metering installations have been tried, and fast powerful diagnostics revealing failure or degradation of components are available.

AN OLD CONCEPT.

Turbine meters have been used for the measurement of fuel gas for nearly a century. They were based on earlier anemometers used for measuring wind strength and air currents in mines (Ref. /1/). The main difference is that whereas anemometers measure velocity at a point, turbine meters cover the entire duct.

Bonner and Lee (Ref. /2/) mention a patent applied for in 1901 by one Thomas Thorpe of Whilefield near Manchester. From following patents it is quite clear that the fuel gas industry was the target market. Gas was an expensive commodity at that time, mostly used for lighting. It was manufactured from coal, and the nature of that process was such that the gas was at low pressure.

Up to the sixties turbine meters were already manufactured in all sizes of which the largest reported by Bonner and Lee is one, measuring 1 m in diameter, used to measure coke oven gas at Dutch State Mines.

Most applications were at low pressure and one of the challenges for the meter designer was to lower the minimum flow rate that could be measured as much as possible by using very light rotors and bearings.

For turbine meters individual calibration was a necessity for any degree of acceptance. Meters capable of accurately determining gas quantities were available even in the early days. Very large "wet" positive displacement meters had accuracies that would even today be very acceptable.

The calibration was of course at low pressure, the application being at low pressure, and also because no alternative calibration methods were available. Thus the calibration with atmospheric air found its way into codes and regulations, and still figures today in OIML recommendations and most National standards and regulations.

According to these standards the meter has to show an error between certain limits when tested with air of atmospheric pressure. This requirement has to be met regardless of whether they will ever serve under those conditions.

In the 60's Lee, Evans and Karlby at Rockwell (Ref. /3/, Ref. /4/) did fundamental research on turbine meters for liquid and gas. This work resulted in the present gas turbine meter, capable of stable, reliable and accurate measurement over long periods of time as it is presently used. It was the availability of a high pressure test installation that made it possible to attain the superior performance of these meters.

Though of U.S pedigree, the application of turbine meters for high pressure gas metering occurred on a much larger scale in Europe than in the U.S. All the gas from the Slochteren field sold in the Netherlands to date has at least once been measured by a turbine meter.

HIGH PRESSURE CALIBRATION.

As mentioned above, it was really the availability of the Rockwell high pressure test loop at Dubois that made it possible to check the theories of Evans, Lee and Karlby and to design meters on this basis.

Of course, field tests had been made at elevated pressures both in the U.S. and in Europe, often with orifice plates as the reference. Repeatability of the tests and traceability of the reference are of a limited accuracy under those conditions and not suitable to improve performance significantly. Only with a dedicated installation equipped with traceable accurate reference standards, can major improvements be made.

In Europe, Gaz de France was probably the first to systematically investigate the performance of turbine meters at high pressure in their dedicated research facility in Alfortville (Ref. /5/). Their tests showed a significant influence of the pressure on the error of some of the meters they tested.

Gasunie, to reduce the uncertainty in their measurements, built three test facilities for high pressure calibration, and were the first to test each meter they had in use individually at operating conditions (Ref. /6/).

Other research and testing facilities for high pressure gas were built in Europe and intercomparisons were made to assess the accuracy of their results (Ref. /7/, Ref. /8/).

Calibration of meters can now be carried out at operating conditions for most applications, and the reasons for a calibration at low pressure have disappeared.

Tradition, however, dictates that in many countries it is still required that any meter shall be approved with atmospheric air.

PHYSICS OF THE TURBINE METER

The ideal turbine meter would have no retarding forces, infinitely thin rotor blades, total driving force concentrated at the mean blade radius and a uniform fluid velocity distribution entering the blades in an axial direction.

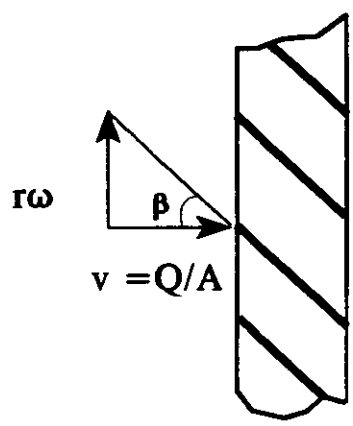

Figure 1. Velocity diagram for rotor radius (r) ideal case

From the blading diagram (Figure 1) it can be seen that for the ideal turbine meter, the rotational speed of the rotor would be:

1) $\omega_i = \tan \beta . Q / r.A$, where:

r	=	the mean radius of the rotor
A	=	the annular flow are
β	=	the blade angle
Q	=	the volume flow rate
ω_i	=	the (ideal) rotational speed of the rotor

and

V = Q/A

V = the velocity of the gas

for a given meter.

Equation 1) simply states that the rotor speed is directly proportional to the flow rate.

Thus by counting the number of revolutions of the rotor and scaling them for their apparent volume, the volume that has passed through the meter can be totalized. This characteristic is similar to a positive displacement meter.

In the real turbine meter there is a drag due to the mechanical friction of the bearings and gearing, as well as fluid drag on the blades and the hub.

The ratio ω/ω_i would indicate the per cent registration of the actual meter to the ideal meter. This per cent registration can be equated as the ratio of the driving forces to the retarding forces (Ref. /3/).

2) $\omega/\omega_i = PR = 1 - (M_R / M_d)$, where:

PR	=	Per cent registration
M_R	=	Total retarding torque
M_d	=	Available driving torque

The percentage registration is related to the error as

$E = (\omega - \omega_i)/\omega_i = PR - 1$

The available driving torque M_d is proportional to the kinetic energy of the fluid or:

3) $M_d = k.\rho.Q^2$

M_d = driving torque
ρ = fluid density
Q = volume flow rate
k = constant
and the retarding torque M_R :

4) $M_R = M_f + M_n$, where

M_f = retarding torque due to fluid forces
M_n = retarding torque due to mechanical forces.

Substituting in equation (2) yields:

5) $PR = 1 - [\, K.(M_f + M_n) / \rho.Q^2 \,]$, with

$K = 1/k$

If the retarding torques can be regarded as constants then this equation simply states that for the meter to achieve its required accuracy, the retarding forces should represent only a fraction of the available driving torque.

Since the driving torque is directly proportional to the fluid density, and the density of gas is very small at low pressure, the retarding torques in the meter must be kept as small as possible for good low pressure performance. Mechanical friction forces should also be kept small in relation to the driving forces because they are less stable.

It should be noted that the energy extracted from the fluid is the amount required to overcome the retarding torque, and at higher densities, the available energy is far greater than required. Further, the retarding torque must be small, or proportional to the driving force, to have linear relationship for the accuracy of the meter.

It is usual to equate hydrodynamic forces in terms of dimensionless friction factors or drag coefficients:

6) $M_f = C.\rho.Q^2/2$

Lee and Karlby (Ref. /3/) separated the fluid drag in two parts, one (C_f), that is dependent on Reynolds' number and one that is not (C_s).

7) $C = C_f + C_s$

The Reynolds' independent part results in a constant percentage error.

8) $PR = 1 - K.C_s/2 - K.(C_f/2) - K.M_n / (\rho.Q^2) = A - f(Re) - K.M_n / (\rho.Q^2)$ with

A a constant.

The Reynolds' number dependent part behaves as the classical friction factor (Figure 2) and the form is reflected in the curve of the percentage registration PR as a function of Reynolds' number (Figure 3).

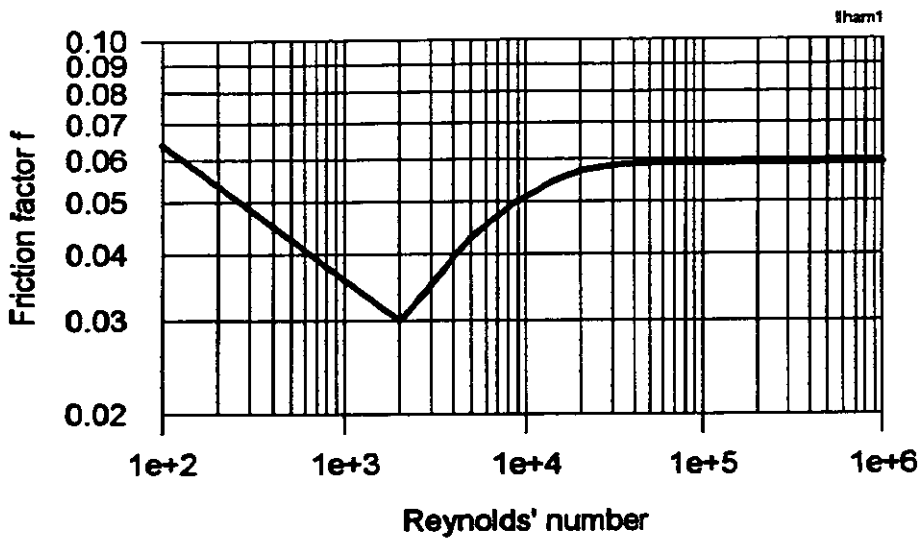

Figure 2. Friction factor f as a function of Re

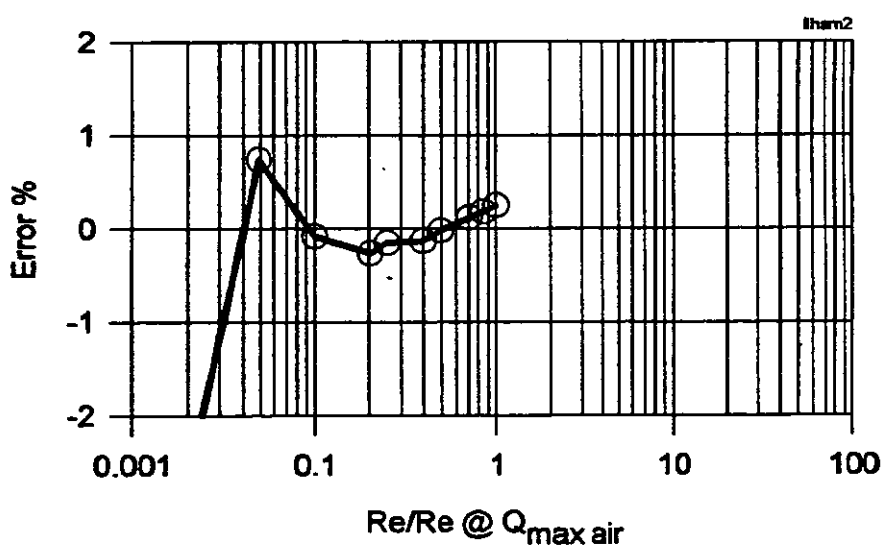

Figure 3. Calibration curve for original meter for atmospheric air

The turbine meter *minimum flow rate* is determined by the mechanical friction M_n. A series of tests with air at low pressure usually establishes the flow rate at which the meter achieves acceptable registration. The minimum flow rate for any other set of conditions can then be determined by equating the new conditions to the minimum conditions determined by test. Since the driving torque must be equal for both conditions, it can be expressed as follows:

9) $$M_n = [\rho_{air\ base}\, Q^2_{min\ air}] = [\rho_m\, Q^2_{min\ operating}]$$

where $\rho_{air\ base}$ is the density of air at base conditions at which the minimum flow test was carried out, and ρ_m the density of the measured gas at operating conditions.

From this we find for the minimum flow rate under operating conditions:

10) $$Q_{min\ operating} = Q_{min\ air}\sqrt{\left(\frac{\rho_{air\ base}}{\rho_m}\right)}$$

From figure 3 it is clear that for low Reynolds' numbers the meter linearity suffers. In order to keep the calibration curve within the legal tolerances, it may for some meters be necessary to lower the Reynolds' number at which the flow becomes turbulent. Several ways exist to achieve this. Eujen (Ref. /9/) gives a description of a meter where the gas expands from a ring shaped nozzle onto the turbine wheel. In this design, the driving force now also becomes dependent on the Reynolds' number, and the form of the equations governing the meter behaviour also becomes more complicated. In general one can say that means to force the transition from linear to turbulent to lower Reynolds' number, complicate the design and also the behaviour of the meter. It introduces more parameters that tend to make meter behaviour less predictable.

Axial forces

Though the design of the meter is such that axial forces should in first approximation be compensated, it is clear that any remaining axial force will increase, proportional to the velocity head. These forces will therefore increase linearly with pressure. Axial forces on the turbine wheel may result in slight displacements or deformations that affect accuracy. These effects may not be noticeable at low pressure.

The above shows that the requirement for a calibration curve that is inside the legal limits for the low Reynolds' numbers of atmospheric air, determines the design of a turbine meter to a large extent.

The behaviour of present generation turbine meters is excellent as is shown in a paper by van der Kam (Ref. /6/). Operating experience at Gasunie showed that the few cases when problems arose, could be attributed to one or more of the following causes:

Bearing problems

Contamination problems

Bearing problems may result from contamination or from overloading or just wear. The result is an uncertainty of the position of the rotor which may affect the accuracy. For high pressure use, an increase in bearing friction would be insignificant in most cases, as sufficient driving power is available.

Contamination may take the form of deposits in the flow channel or on the blades. Solid particles may be jammed between rotor and flow channel, damaging the rotor and/or its bearings.

With this experience a research project was started in co-operation with Gasunie to design a meter that was less vulnerable to contamination, and with a stronger bearing arrangement, in short, the design of a High Stability Turbine meter.

Project design

The project was designed to investigate the following parameters:

The effect of removing the mechanical counter.

The influence of bearing size on minimum flow rate.

The effect of removing any rims or recesses that are presently used to improve low pressure calibration.

The clearance between rotor and housing and its influence on the calibration curve.

Experiments were carried out at Instromet B.V. in Silvolde with air of atmospheric pressure, at Instromet's 8 bar test facility in Utrecht, at the Gasunie test station in Groningen at pressures of 8 and 20 bar and at Gasunie's Bernouilli Laboratory in Westerbork at 60 bar.

Two sizes were used for the experiment. Initially a 12" meter was used to determine optimum design values. This was checked later with a 6" meter to determine whether the scaling rules would apply.

Both meters were first designed to be able to pass low pressure calibration. The calibration curves obtained with this design served as reference.

The effect of the mechanical counter

The mechanical counter is driven by the turbine wheel through a reduction gearing. A magnetic coupling provides a leak-tight feed from the pressurised part to the outside. In its simplicity, it provides a reliable back-up for the sophisticated data collection and conversion that is used in modern gas metering. Its insensitivity to electromagnetic interference and even lightning, and its independence of electricity supply or batteries are valued specifically by customers in remote and hostile environments. It does, however, exert a drag.

Electronic pick-ups need negligible amounts of energy and it was sensible to check whether it would be advantageous to replace the mechanical counter by an electronic one. The small drag the mechanical counter causes, would perhaps better be spent in heavier bearings.

Eliminating the mechanical counter, however, did not result in any measurable change in the calibration curve, even with air of atmospheric pressure.

Bearing size

Heavier bearings will have the effect to increase the retarding torque and therefore increase the minimum flow rate. The magnitude of the effect was experimentally determined.

With atmospheric air the calibration curve dropped about 1 % at 10% of maximum flow rate. However, for gas at 8 bar the curve dropped only 0.5% at 5% of Q_{max}.

This proved that the envisaged bearings would be suitable for use at transmission pressures.

Eliminating recesses in the flow channel

As was explained earlier, turbulence is deliberately introduced to move the transition point from laminar to turbulent to lower Reynolds' numbers. If this is not done, the meter will overregister at these low Reynolds' numbers. For small size meters the effect of the laminar flow is wholly or partly compensated by the drag from bearings. For larger size meters the transition point to turbulent flow has to be lowered to have a sufficient linear range.

Figure 4 gives the calibration curves at different pressures for the meter of figure 3, but with heavy bearings. In figure 3, the effect of the laminar flow regime is clearly visible. Heavier bearings, as in figure 4a, clearly compensate the effect. Eliminating the recesses that induce early turbulence gives indeed a dramatic change in the calibration curve (Fig. 4b).

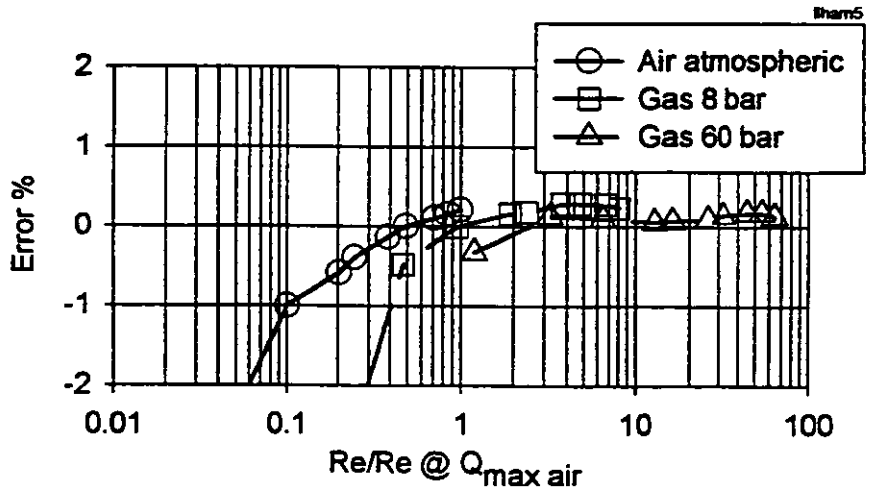

Figure 4a. Calibration curve for the same meter as of figure 3 with heavier bearings

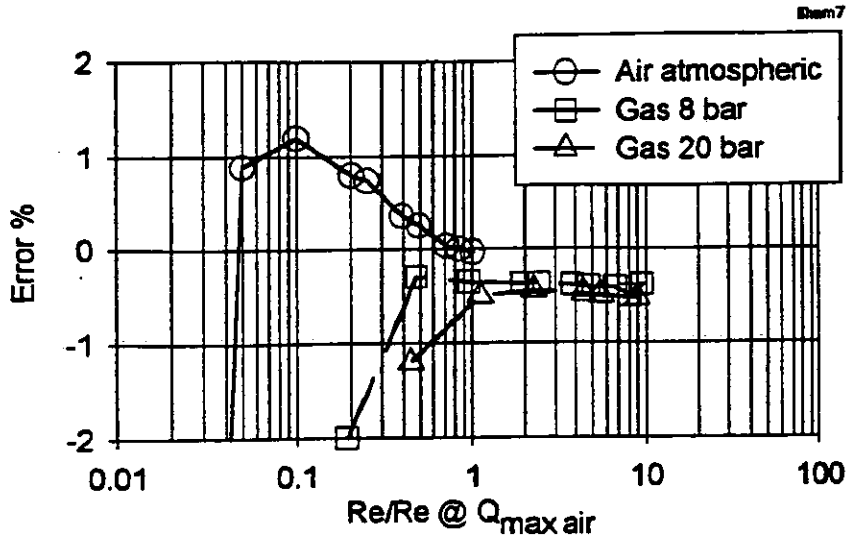

Figure 4b. The same meter as in figure 4a but now without any recesses in the flow duct

The laminar region now peaks for a value of the normalised Reynolds' number of 0.1 instead of 0.05 as in figure 3. The Reynolds' number is normalised with respect to the value of Re with air of atmospheric pressure at maximum flow rate. The clearance between rotor and flow channel for the meter of figure 4b is very small.

Plotting measured data as a function of Reynolds' number, a single continuous curve is found if the friction at the lower flow rates, where it becomes important, is compensated for. This is illustrated in figures 5 and 6, where first the raw data are plotted as a function of the Reynolds' number and then a correction is mathematically made to the data to compensate for a certain mechanical drag. If the right value for the mechanical drag is introduced, a single smooth curve is indeed obtained. Of course, any systematic difference in the different calibration laboratories would still remain.

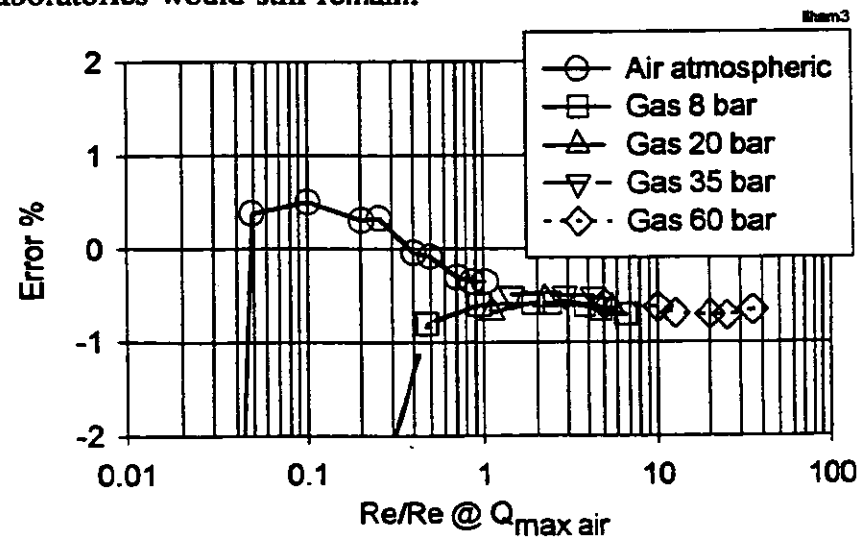

Figure 5. Calibration curve for meter with heavy bearings and increased clearance measured at different pressures

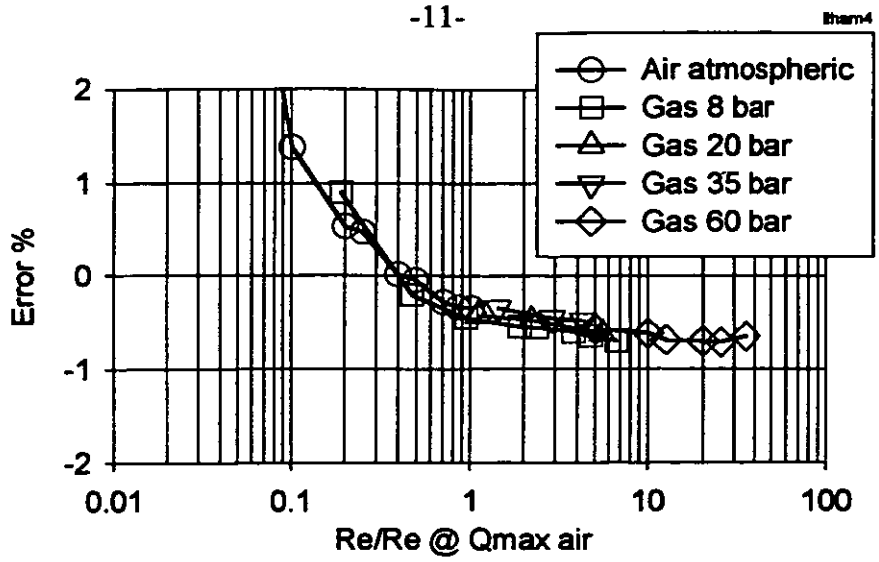

Figure 6. The same data as in figure 5, but now compensated for mechanical friction.

A problem that is difficult to prevent in practice is the presence of particles in the conduit. Welding beads may still be present in nominally clean piping, and start moving when flow rates are high. It was therefore decided to increase the space between rotor and housing to allow a passageway for these types of particles. For example in the configuration of figure 5 and 6 the clearance between rotor and flow channel has been somewhat increased with respect to figure 4b.

A number of different clearances were tried. It was found that the clearance could indeed be increased considerably without significantly affecting the performance of the meter (Figure 7). The form of the calibration curve remains the same but drops, as the blockage and therefore the velocity is reduced. For very large clearances the repeatability of the data becomes less.

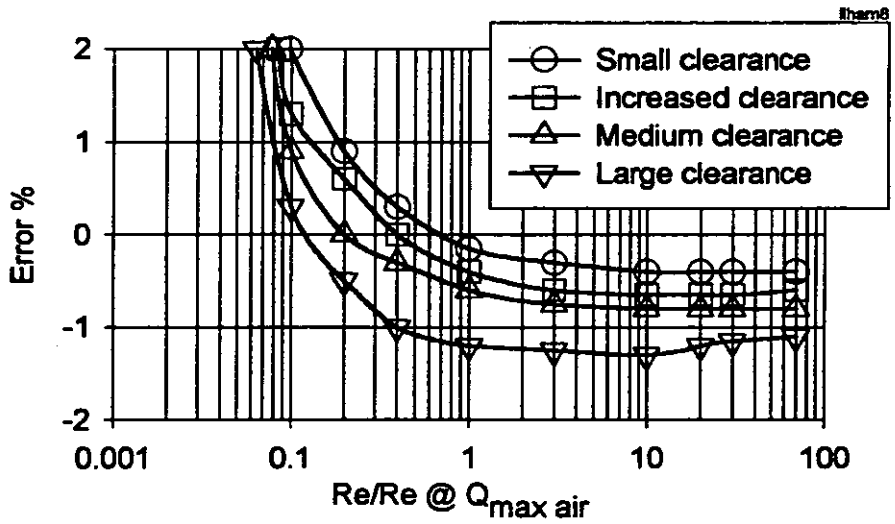

Figure 7. Calibration curves for different clearances between rotor and flow duct

In conventional meters, similarity of performance with Reynolds' number is limited to the fluid related variables: flow, density and viscosity. The geometry is too complicated to scale.

A 6" meter was also equipped with heavier bearings and recesses in the flow duct were removed. Similar experiments were then performed and it now proved possible to also scale the linear dimension (Figure 8). This illustrates that the performance for meters of this design can be better controlled, thus adding another tool for quality control. It is not sufficient now for these meters to have a calibration curve that falls within the limits set by OIML or legal metrology. The curves of these meters have to match a specific pattern as a function of Reynolds' number.

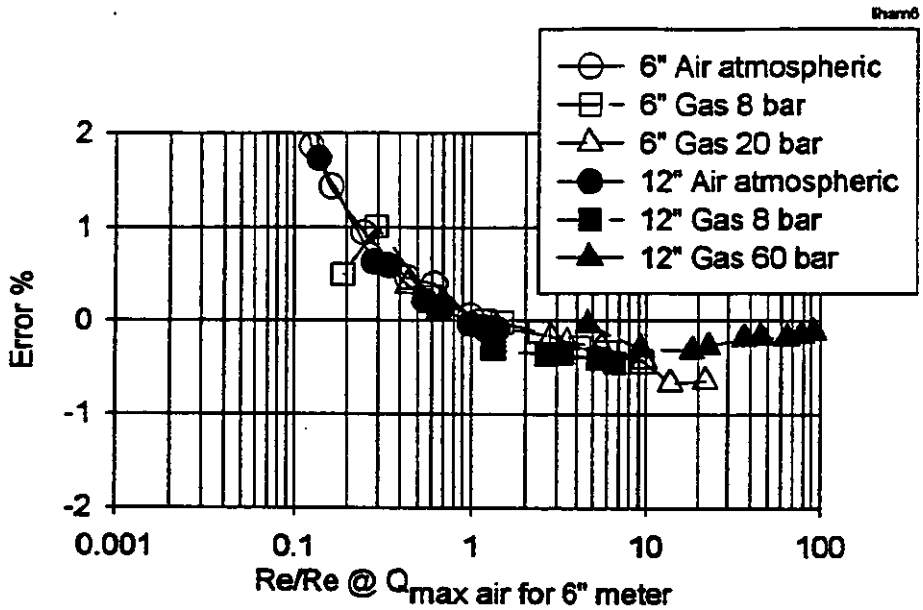

Figure 8. Calibration curves for 12" and 6" as function of Re (Data compensated for mechanical friction)

X4X STRAIGHTENER

Parallel to the High Stability project, research had been carried out to design a straightener that could be built into the same standard 3D length of the SM-RI meter and would satisfy the requirements that are set out in ISO 9951 (Ref. /10/). The standard requires the manufacturer to specify the installation conditions necessary for a specific set of flow perturbations to have not more than 0.33 % influence on the calibration curve.

The low level perturbation as specified in ISO 9951 consists of two elbows in two perpendicular planes, a concentric expander to the next pipe size and a 2D straight pipe. The high level perturbation is similar , except that a half area plate is mounted in between the two elbows with the opening towards the outside radius of the first bend. The perturbators are drawn in figure 9. They can be arranged to give a clockwise or anti-clockwise swirl.

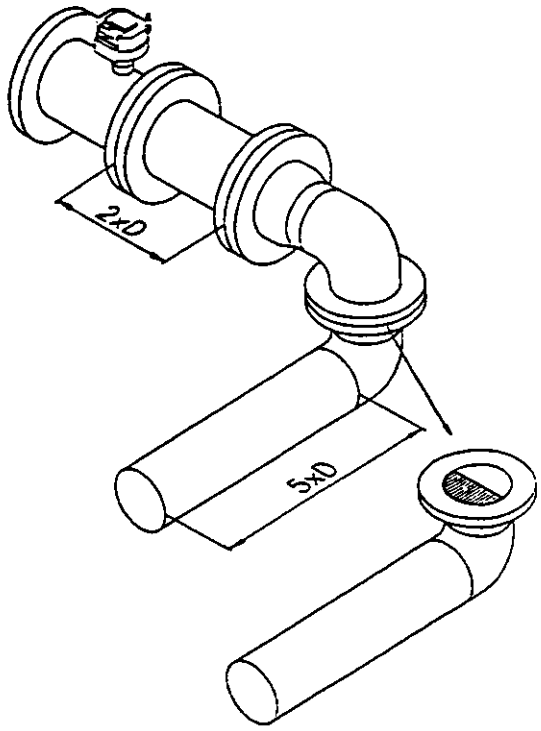

Figure 9. Flow perturbations according to ISO 9951

The research resulted in the development of the X4X straightener. This straightener, built into a normal 3D length turbine meter, satisfies the requirements of the standard without additional length or external straightening devices. Figure 10 shows the measured influence of the high level perturbations on a 6" meter.

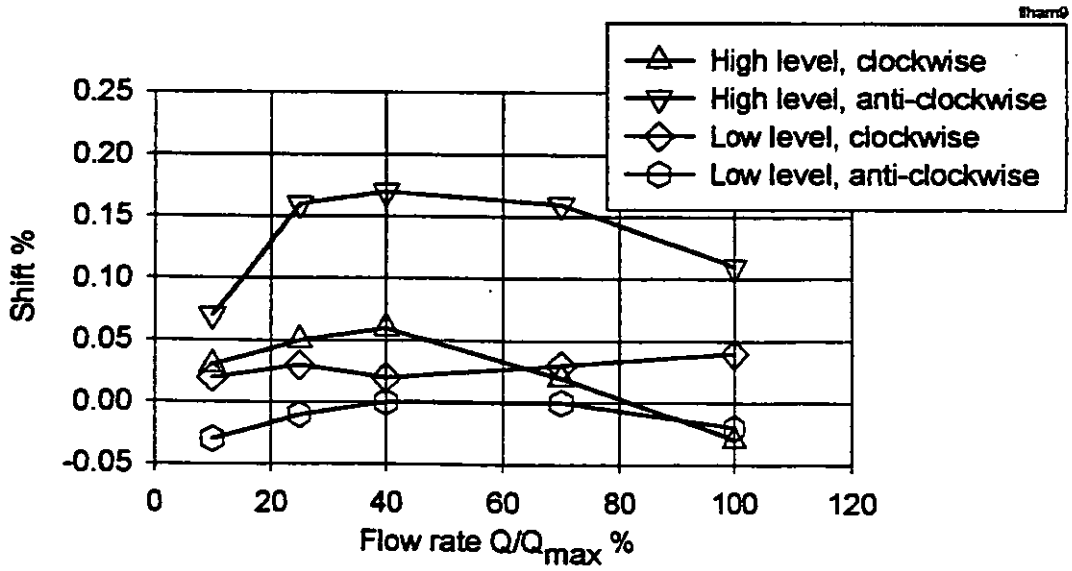

Figure 10. Shift in calibration curve for a 6" turbine meter equipped with an X4X straightener when tested with ISO 9951 perturbations using atmospheric air.

It was logical to incorporate this straightener in the new High Stability design as it makes it possible to greatly reduces the size of installations. It proved to be possible to incorporate this straightener without affecting the calibration curves. At the time of writing, a 16" meter with X4X straightener and High Stability design is undergoing an endurance test.

DIAGNOSTICS

The increased importance that is attached to accurate and reliable metering has led to the construction of metering stations with two meters in series. In general, the indication of the two meters will not be exactly the same. The difference between the meters should however be small and constant. In case one meter fails, the difference between the two meter indications will change. The risk of both meters failing to the same extent at the same moment is very small. Automatic detection systems on this basis can not only detect any failure or drift at an early moment, they can also prevent unnecessary scheduled maintenance.

Different philosophies exist with regards to the choice of the meter types. Distrigaz (Ref. /11/) has considerable experience in systems with two turbine meters. This system has proved not only to be very accurate but also very fast. Any deviation in a meter of more than 0.15 % is detected within one hour. Practice has shown that even fouling, which one could expect to have the same effect on both meters, does not happen at the same time at the same rate, and will be detected.

In a metering station with several runs in parallel this leads to a system with a number of identical units that can all be intercompared and, if desired, interchanged.

In Germany, the requirement is for two meters of different operating principle. Both vortex meters and ultrasonic meters are used. Though the use of two different measuring principles gives even more certainty that the meters do not change at the same time, it may also create some problems. Range and repeatability need not be the same, and dynamic response of the meters is different. In general this would lead to more complicated decision strategies for error detection and/or a slower or less accurate diagnosis. Installations with a vortex meter as back-up become rather long, as the latter requires a considerable straight length. Combination of a turbine meter and the Instromet Q-Sonic would technically not require such long straight lengths, as the Q-Sonic is quite insensitive to perturbations in the velocity profile and can be installed in close proximity behind a turbine meter.

There are a number of reasons why a diagnostic system as above can be less attractive. Space may be a constraint, or the cost of a full back-up system considered too high for the station. In such cases a diagnostic system that in itself does not provide full metering capability can be chosen.

An early example of such a system, relying on turbine meter technology is the Equimeter Auto-Adjust (Ref. /12/). In this meter two turbine wheels are mounted, of which the second one has a very small blade angle and is subjected to the wake of the first. Under normal

conditions it would turn very slowly and at a constant fraction of the speed of the first. Most malfunctions of the first turbine wheel will affect the swirl in its wake and show up in the ratio of the rotational speed of the two wheels. In fact, for a number of failure modes, the difference of the two rotor speeds is still an accurate measure of the flow rate.

Alternatively other measuring principles could be combined with a turbine meter and made into one instrument. Several possibilities are investigated by Instromet at this moment. It will be clear that one of these is the ultrasonic principle.

Such instrument would reliably detect any drift or malfunction but not necessarily have self-correcting capabilities.

ACKNOWLEDGEMENT
The co-operation of NV Nederlandse Gasunie and in particular of Dr. P.M.A. van der Kam and Mr. de Nobel is gratefully acknowledged.

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Main Index

North Sea FLOW Measurement Workshop 1995

Paper 26:

ASSESSMENT OF THE METROLOGICAL PERFORMANCES OF A DELIVERY STATION

5.7

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ASSESSMENT OF THE METROLOGICAL PERFORMANCES OF A DELIVERY STATION.

Vincent de LAHARPE, Doris KING, Paul KERVEVAN

Gaz De France

ABSTRACT

Gaz De France is leading an important research programme on the installation conditions of flow meters. As part of this programme we have made laboratory tests on a gas regulating/metering station (35 → 5 bar).

Two different turbine meters, a G650 (Qmax=1000 m3/h) and a G400 (Qmax=650 m3/h), have been calibrated and than tested in the delivery station. Large additional reading errors have been observed (in the order of ±3%) under normal working conditions.

We have then measured the axial and tangential velocity profiles at the meter location with a special self acting device. We have discovered the presence in the flow of strong perturbations that explain the meter reading errors. Some solutions have been recommended and successfully tested.

These tests highlight the necessity to improve the standards and to develop on-site diagnostic tools able to characterise the flow perturbations under real working conditions.

INTRODUCTION

In the gas metering stations the flow meters are often installed downstream of pressure regulators, single bends, double bends out-of-plane, diffusers, valves and other obstacles. The researches lead by all the gas companies in the past years have shown that each of these elements produces flow perturbations which turbine meters are sensitive to. In the delivery stations, the coupling of these various disturbing elements and the superposition of their effects can induce significant reading errors on turbine flow meters. In such conditions their calibration curve, obtained for ideal flow conditions, can no longer be considered as a reference.

Conscious of these problems, the gas companies and the regulatory authorities have established standards (AGA3, ISO9951, CEN/TC237, etc.) and internal recommendations that specify requirements and tests for the design and performance of gas meters and gas metering stations. the standards provide in particular standardised perturbation tests to assess the sensitivity of turbine gas meters to upstream installation conditions. These perturbation tests were supposed to represent the perturbations produced by piping elements such as bends, tees, convergent or divergent sections (low level perturbations), or those produced by regulators or other throttling devices (high level perturbations).

Although these standards, recommendations and perturbation tests had been adequate by the time they were established, They are no longer sufficient today. The gas regulating/metering stations are increasingly compact and the expansion ratios increasingly high,thus involving higher levels of perturbations. The standardised perturbation tests are no longer representative of the real installation conditions in such compact regulating/metering stations. The gas turbine meters that successfully go through the perturbation testing may still indicate large reading errors in those stations. This is demonstrated by the tests presented in this report.

The tests have been carried out on a gas metering station complying with ISO9951 and Gaz De France recommendations. Its geometrical configuration is one among the great variety of existing configurations. It has been selected because it shows the high levels of metering errors that gas companies are exposed to with nowadays compact installations. Two turbine meters, a G650 and a G400 have been calibrated in the station for various operating conditions. Velocity profile measurements have been completed to determine the flow conditions at the meters inlet and to understand their behaviour. Solutions have been provided.

EXPERIMENTAL SET-UP

Figure 1 shows the plan of the delivery station. It is a regulating/metering station designed for the operation on the transportation network. It comprises of two regulating lines and of one turbine meter. The main line, L1, is equipped with a "silent regulator" and the security line, L2, is equipped with a "standard regulator". The meter is installed 5.2 diameters downstream of the last bend, in a 150 mm bore section (6"). Under normal operating conditions the meter is fed by the main line equipped with the silent regulator.

Two turbine meters, a G650 (Qmax=1000 m3/h) and a G400 (Qmax=650 m3/h), have been tested in the station at an absolute pressure of 5 bar. The tests have been carried out in four phases:

Phase 1: Behaviour of the meters in the station for the normal configuration for two pressure ratios.
Phase 2: Behaviour of the G400 after inversion of the regulators.
Phase 3: Technical solutions.
Phase 4: Velocity profile measurements.

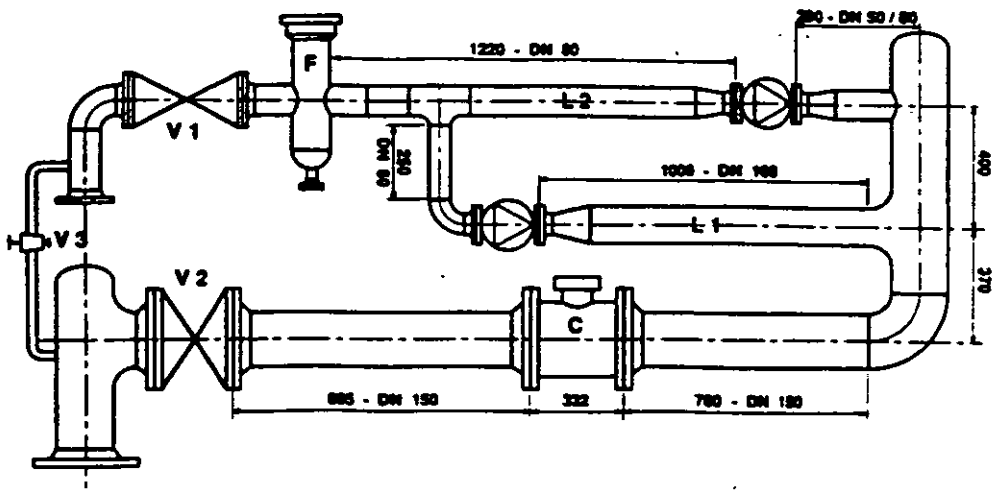


Figure 1 - Plan of the gas regulating/metering station

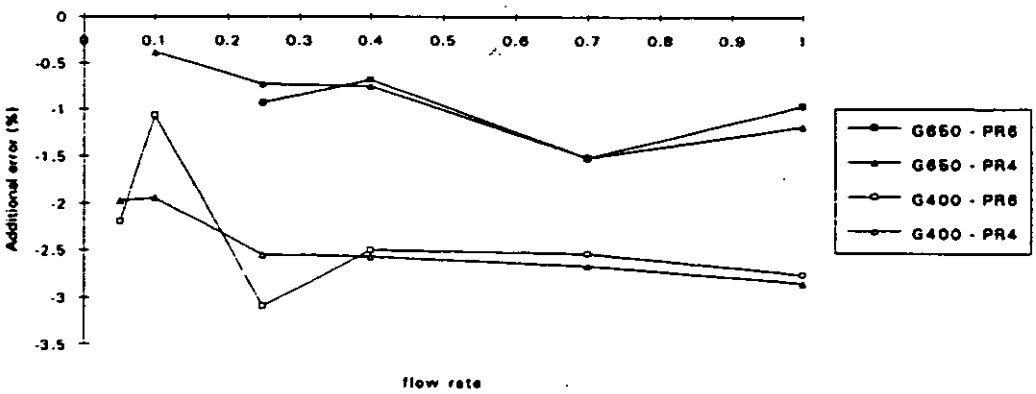
RESULTS AND DISCUSSION

Phase 1

We have tested each turbine meter at 5 bar (abs) in the station as originally configured: with the silent regulator in the main line and with the standard regulator in the security line, for each case two pressure ratios have been investigated: 6 and 4.

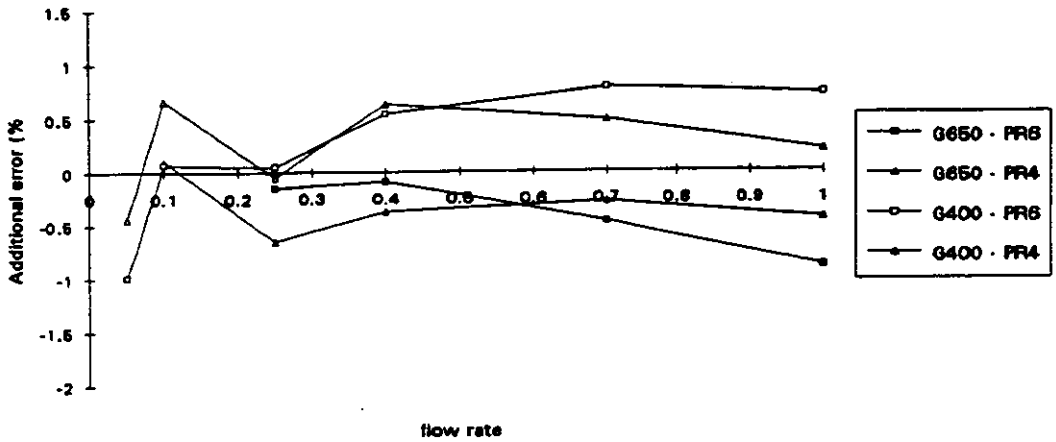
Figure 2 shows the additional error curves obtained for the two turbine meters under normal working conditions, that is when the main line is operating with the silent regulator. There is a strong influence of the installation conditions on the meters. The additional error, calculated with respect to the reference curve obtained for ideal flow conditions, varies between -1% and -1.5% for the G650 and between -1% and -3% for the G400. The pressure ratio does not have a significant influence on the metering accuracy.

Figure 2 - Silent regulator in main line



The additional error curves shown on figure 3 are obtained when the security line is operating with the standard regulator. In this configuration the metering is improved. The additional error of the G650 is reduced to 0% to -0.8% and the additional error of the G400 is reduced to -0.5% to 0.7%. Also, for this regulator the pressure ratio does not have a significant influence on the meter error.

Fig. 3 - Standard regulator in the security line



Below, table 1 summarises these tests giving the deviation. The deviation is the weighted mean additional error calculated according to the following formulae:

$$\text{deviation} = \frac{\sum_{i=1}^{n} (Q_i/Q_{max}) * E_i}{\sum_{i=1}^{n} (Q_i/Q_{max})}$$

where Q_i/Q_{max} is a weighting factor, E_i is the additional error of indication at the flow rate Q_i. For $Q_i = Q_{max}$ a weighting factor of 0.4 is taken instead of 1.

Table 1

Configuration	Silent regulator on main line		Standard regulator on security line	
Pressure ratio	6	4	6	4
deviation of G650	-1.03 %	-1.08 %	-0.40 %	-0.35 %
deviation of G400	-2.56 %	-2.61 %	0.54 %	0.37 %

Phase 2

From the results of phase 1 we have carried out more investigations by reversing the regulators in the station, in order to asses the influence of the type of regulator. The tests have been limited to the G400 and to the pressure ratio of 4. This new configuration places the silent regulator in the security line and the standard regulator in the main line.

The curves in figure 4 show the additional error of the G400 meter when the main line is operating. When the main line is equipped with the standard regulator, there is a large positive additional metering error for flow rates above 0.2 Qmax (+1.5% to +3.5%) and a large negative one for flow rates below 0.2 Qmax (-2% to -4%). Compared with the normal operating configuration (Silent regulator in the main line), there is still a strong influence of the installation conditions but the error is partially inverted. The sign of the error depends on the type of regulator.

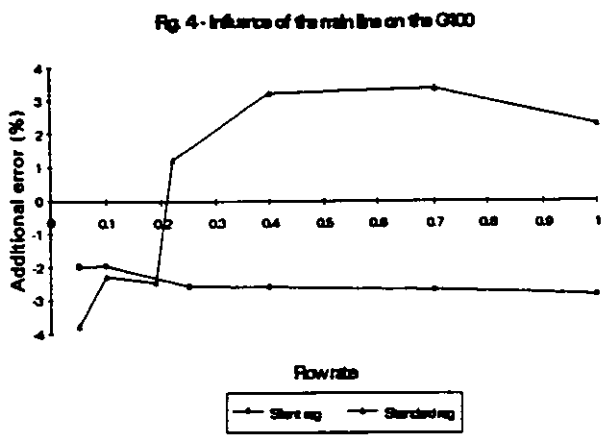


Fig. 4 - Influence of the main line on the G400

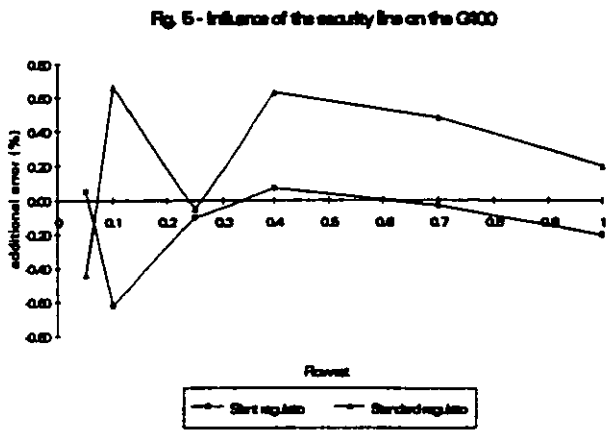


Fig. 5 - Influence of the security line on the G400

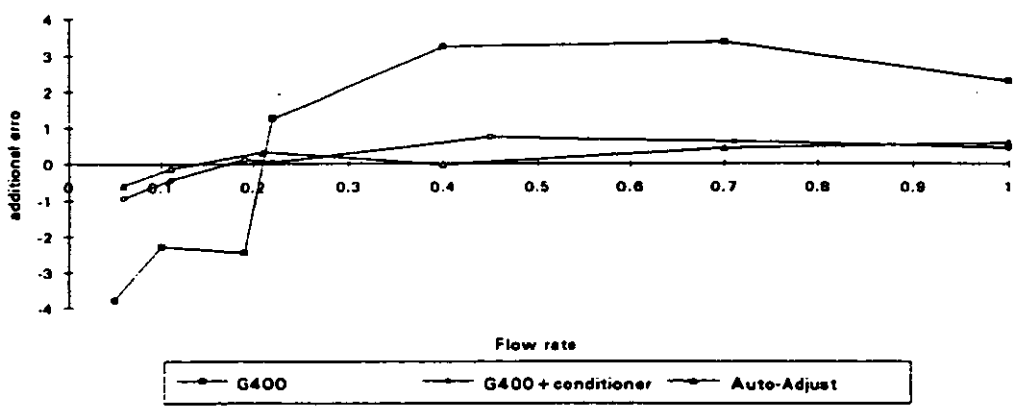
Figure 5 represents the results obtained with the security line operating. The same metering accuracy as for ideal flow conditions is achieved by operating the delivery station with the silent regulator in the security line.

A first conclusion can be drawn from these results: whatever the pressure regulator or the meter, the operation of the station by the main line involves large metering errors, whereas the operation by the security line involves comparatively small errors. The most influent factor is the geometry of the pipework upstream of the meter. However, when installed in the security line, the silent regulator gives better metrological performance than the standard regulator. A solution would be to use the line L2 as the main line equipped with the silent regulator.

Phase 3

Two other solutions have been tested and represented on figure 6: the use of a flow conditioner and of an Auto-Adjust turbine meter (twin rotor turbine meter).

Fig. 6 - Standard regulator in main line



The G400 was tested with the standard regulator mounted in the main line, with the flow conditioner directly connected to its upstream flange. The conditioner (see figure 7) consisted of a porous body joined to a short tube bundle. At 5 bar and for the maximum flow rate it generates a pressure loss of approximately 0.5 bar. The error of indication of the meter is significantly lowered and drawn back to an acceptable level.

In the same conditions the additional error curve obtained for the Auto-Adjust turbine meter shows a spectacular improvement of the metering accuracy, compared to the single rotor turbine meter G400.

Phase 4

To understand the results obtained in the first three phases and be able to relate the observed errors to the flow configuration, we have made some velocity profile measurements at the meter location. Figures 7 to 11 show the axial and tangential velocity profiles obtained when the station operates in its original configuration, shown in figure 1 (silent regulator in main line and standard regulator in security line) and downstream of the flow conditioner. Profiles have been measured in each case at 150 m3/h and at 450 m3/h for a pressure ratio of 4.

A velocity profile consists of measuring the axial and tangential velocity on four diameters at different angular positions (-45°, 0°,45° and 90°). 30 measurement points are taken per diameter. This is realised by a self acting device that automaticaly displaces a hot wire probe in the section. One profile measurement takes about 30 minutes. As it is difficult to have a perfectly stable flow rate during half an hour some profiles appear slightly distorded. A positive tangential velocity for the positive x and respectively negative for the negative x, indicates an anticlockwise swirl when looking at the flow coming and vice versa.

In all cases, except with the flow conditioner, the axial velocity profiles are almost symmetric, well developed and there is a fluctuating velocity rate of about 18% to 20%. With the flow conditioner the fluctuating rate is only 4% and the profile is perfectly symmetric. But the axial velocity is much higher on the edge of the section than in the centre. This is due to the shape of the tube bundle being concave and not flat. This might be the reason why the G400 slightly over counts for high flow rates downstream of the conditioner. A simple modification of the tube bundle's shape should improve this situation.

In the case of the main line equipped with the silent regulator there is a strong positive swirl of 18° at both flow rates, indicating a rotation of the flow in the opposite direction of the turbine wheel rotation. This decreases the speed of the wheel inducing a large negative error of indication (see figure 2).

In the case of the security line equipped with the standard regulator there is some swirl but relatively low compared to the previous case: 3° at 150 m3/h and 4° at 450 m3/h. This could be the reason for the slight negative error of the G650 but cannot explain the positive error obtained for the G400.

Observations made by the CERT/ONERA downstream of these two regulators have shown that the silent regulator mainly generates asymmetry whereas the standard regulator generates highly disturbed flows, mainly because of swirl. What is more, the direction of the swirl can vary according to the flow rate. That is probably why the error observed changes sign between the low and the high flow rates, when the main line operates with the standard regulator. Other profiles will be made in this previously mentioned set-up that will probably establish that for low flow rates the swirl is positive and that for high flow rates it is negative.

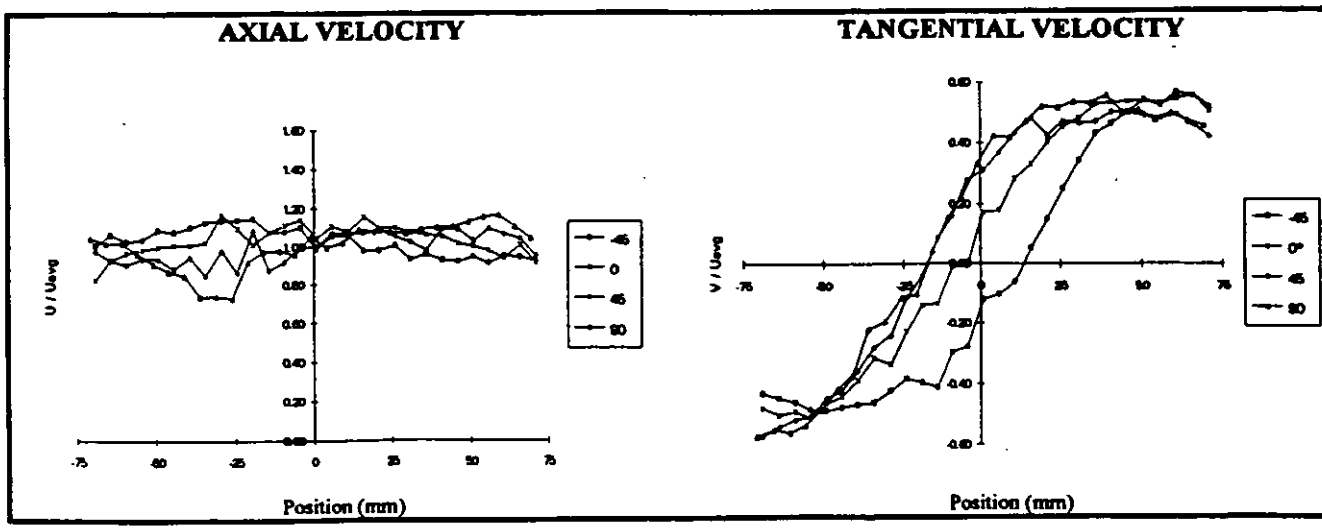


Fig 7: silent regulator in main line - 150 m3/h.

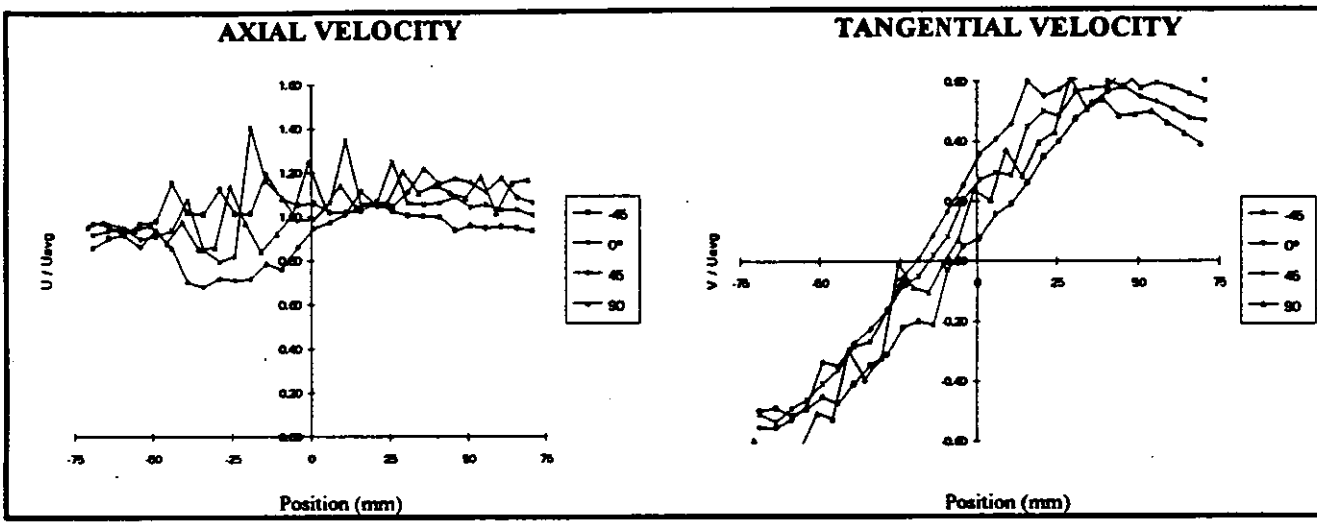


Fig. 8: silent regulator in main line - 450 m3/h

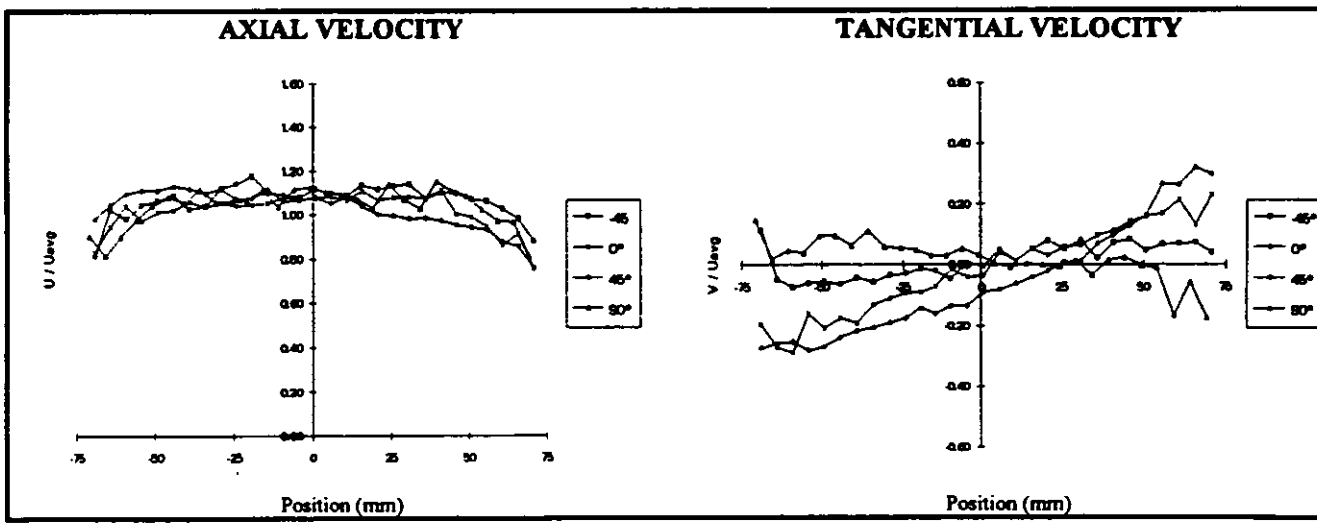


Fig 9: standard regulator in security line - 150 m3/h

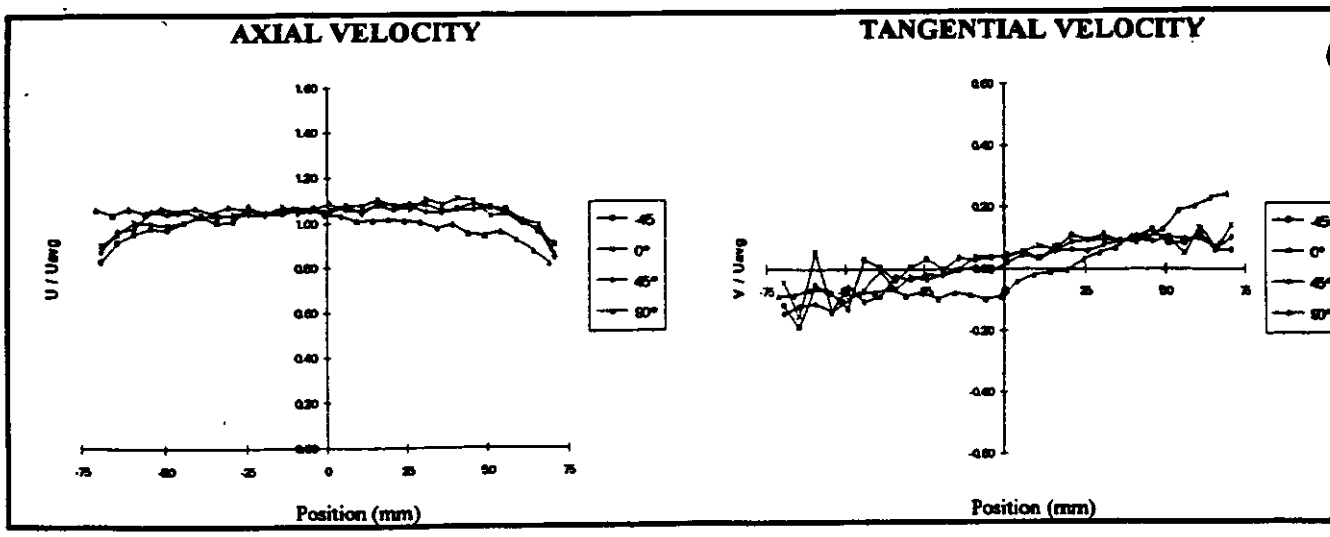


Fig 10: standard regulator in security line - 450 m3/h

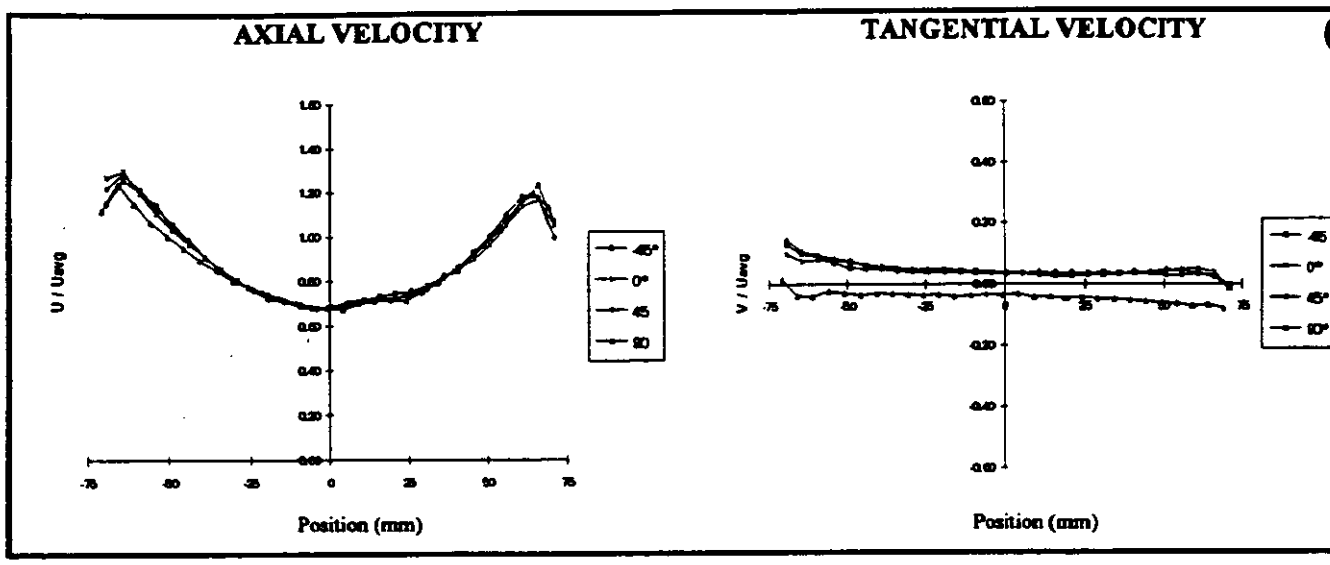


Fig 11: standard regulator in main line with flow conditioner - 450 m3/h

CONCLUSION

These calibration tests demonstrate that the standards and ISO perturbation tests no longer guaranty a good metrological quality. They have to be completed in order to take into account compact installation conditions such as the one we have tested, associating regulators and complex geometrical pipework. The compactness has become a inevitable requirement of modern gas metering stations. So there is an urgent need for the gas industry to find practical solutions, to meet their customers requirements

In order to guaranty the flow metering performance of the gas stations, the gas meter would have to be calibrated including the upstream pipework and the regulator. Because of the large number of existing installations and possible geometrical configurations, this is not possible in practice.

It is necessary to improve the existing standards or to establish new ones to provide precise guidelines for the design and the operation of future metering stations (this is being carried out by the CEN/TC234/WG5).

Concerning the existing metering stations, it is necessary to develop field tools able to measure and characterise the perturbation level at the meter and to provide simple solutions such as flow conditioners. These tests demonstrate that on-site diagnostic tools able to characterise the flow perturbations can help to predict the meter error and, if necessary, to find a solution.

Numerical simulations might also be in the future of great help to better understand the complex flow phenomena in the pipes and to design more compact stations. Their use will allow to reduce the number of tests and to predict the flow velocity profiles where it is difficult to measure them, for example in large stations for industrial customers where it is impossible to stop the gas supply.

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North Sea FLOW Measurement Workshop 1995

Paper 27:

NPD REGULATIONS. RECENT UPDATES. NPD's ATTITUDE WHEN NEW TECHNOLOGY IS INTRODUCED

~~5.6~~

6.1

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CONTENT

1. SUMMARY

A) REGULATIONS

The Norwegian Regulations for fiscal measurement of oil and the equivalent Regulations for fiscal measurement of gas were originally issued in April 1984.

Due to changes in technology but mainly due to changes in the Petroleum Directorate`s inspection/verification philosophy, the fiscal oil and gas measurement regulations were commingeled and reissued in a new format in 1991.(Regulations relating to fiscal measurement of oil and gas etc.)

NPD`s system for administrating the regulations/guidelines is intended to be flexible, it means that when it is needed the regulations/guidelines can in theory be updated annually. It is, however, unlikely that such frequent updates will take place.

The Regulations relating to fiscal measurement of oil and gas etc.(1991), was updated in 1993, and in 1994.

The intention behind the corrections has not been to introduce tighter requirements to the industry, but to eliminate misleading statements and to give guidelines in areas where we occationally have seen dubious quality design.

The 1993 update covered section 33 and 34 of the regulations where misleading statements where changed or deleted. It also covered quite a number of the Re sections in the guidelines, where wider experience/increased knowledge made it obvious that additional text should be added (Re Section 5,9,11,21,25,26,31,32,33,36,41,47,61 and 67).

The 1994 update covered section 5,12,17 and 18 of the regulations. Section 5 was changed due to misleading text. Section 12 and 18 got additional text included to clarify the purpose and thereby avoid unnecessary discussions. Section 17, got new text due to input from the Ministry and the NPD legal department.

The 1995 update also covered an update of the Re sections in the guidelines (Re Section 12,17,23 and 43). Re section 12 and 17, where changed because the sections which they refered to were changed. Re section 23, was changed to give a positive signal to the use of new technology. Re section 43, was changed to give additional technical information.

B) NPD`s ATTITUDE WHEN NEW TECHNOLOGY IS INTRODUCED

The operating companies(licencees) will have to inform the NPD (section 9), if they intend to use measurement equipment or methods not mentioned in the regulations. NPD will then based on the available information decide wheather it is an acceptable solution or not.

All deviations will have to refer to the relevant sections in the NPD, Regulations relating to fiscal measurement of oil and gas etc.
The items which NPD will focus on in such a process is given in viewgraph 1.

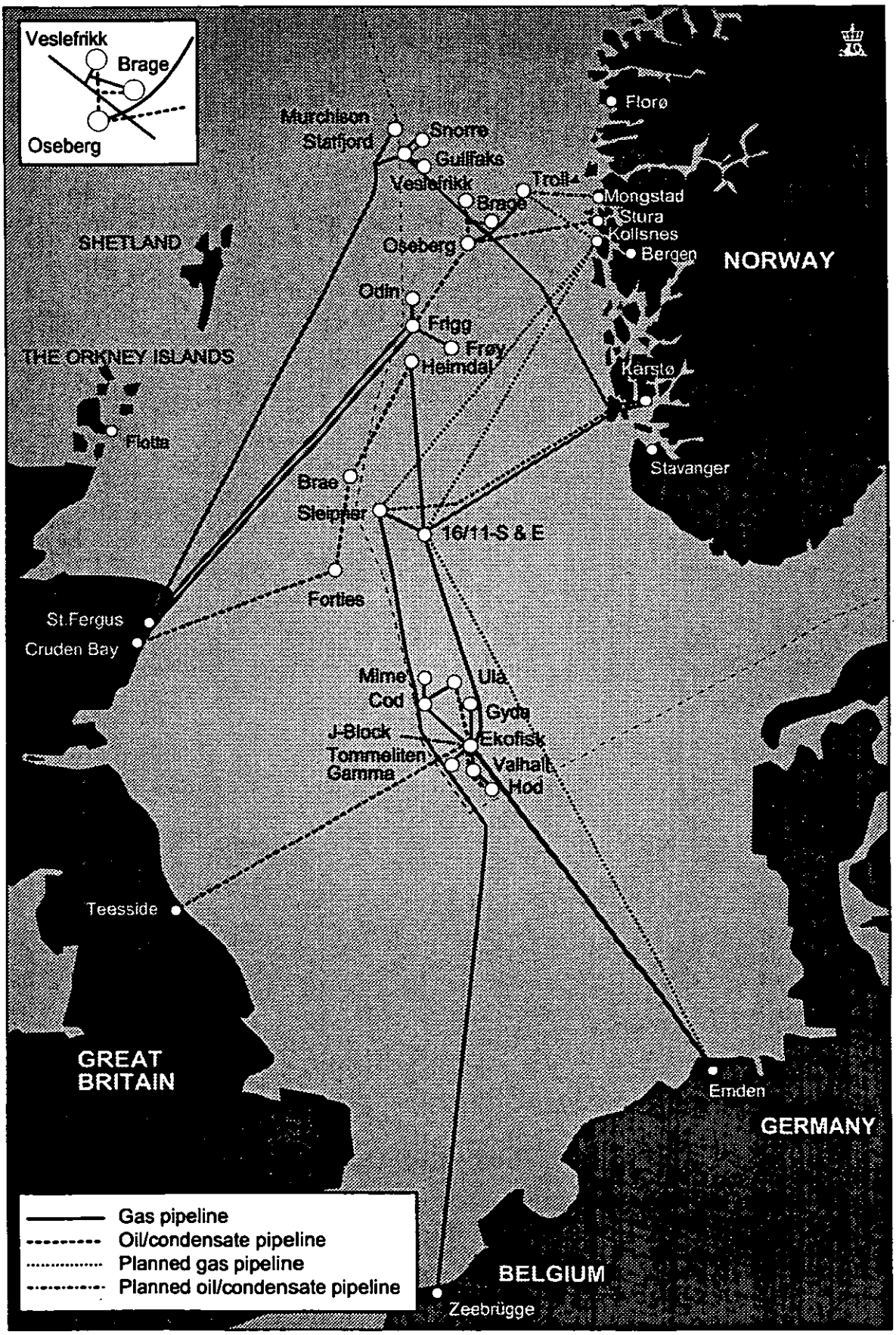
NPD is of course from a general point of view regarding the use of new and more cost efficient technology as very positive.

Our policy in this matter will,however, as a start up be to accept new technology on less critical metering points to build up experience/confidence.

The greatest challenge for a regulatory authority will then be to accept the new equipment at the right time (see fig 2).

It is no doubt that whenever a decision to use new technology is taken, then some people will argue that it is too late, while others will say that it is to early (see fig 3).

Fig. 2.10
Transportation systems for oil and gas from Norwegian North Sea fields



Forskrift om fiskal kvantumsmåling av olje og gass mv

Regulations relating to fiscal measurement of oil and gas etc.
(Unofficial translation)

Veiledning til forskrift om fiskal kvantumsmåling av olje og gass mv
Guidelines to regulations relating to fiscal measurement of oil and gas etc.
(Unofficial translation)

OLJEDIREKTORATET

NORWEGIAN PETROLEUM DIRECTORATE

1995

YA-053

ISBN 82-7257-437-3

THE OIL COMPANIES WILL HAVE TO MAKE SPECIAL APPLICATIONS TO NPD WHEN THEY WISH TO UTILIZE NEW TECHNOLOGY

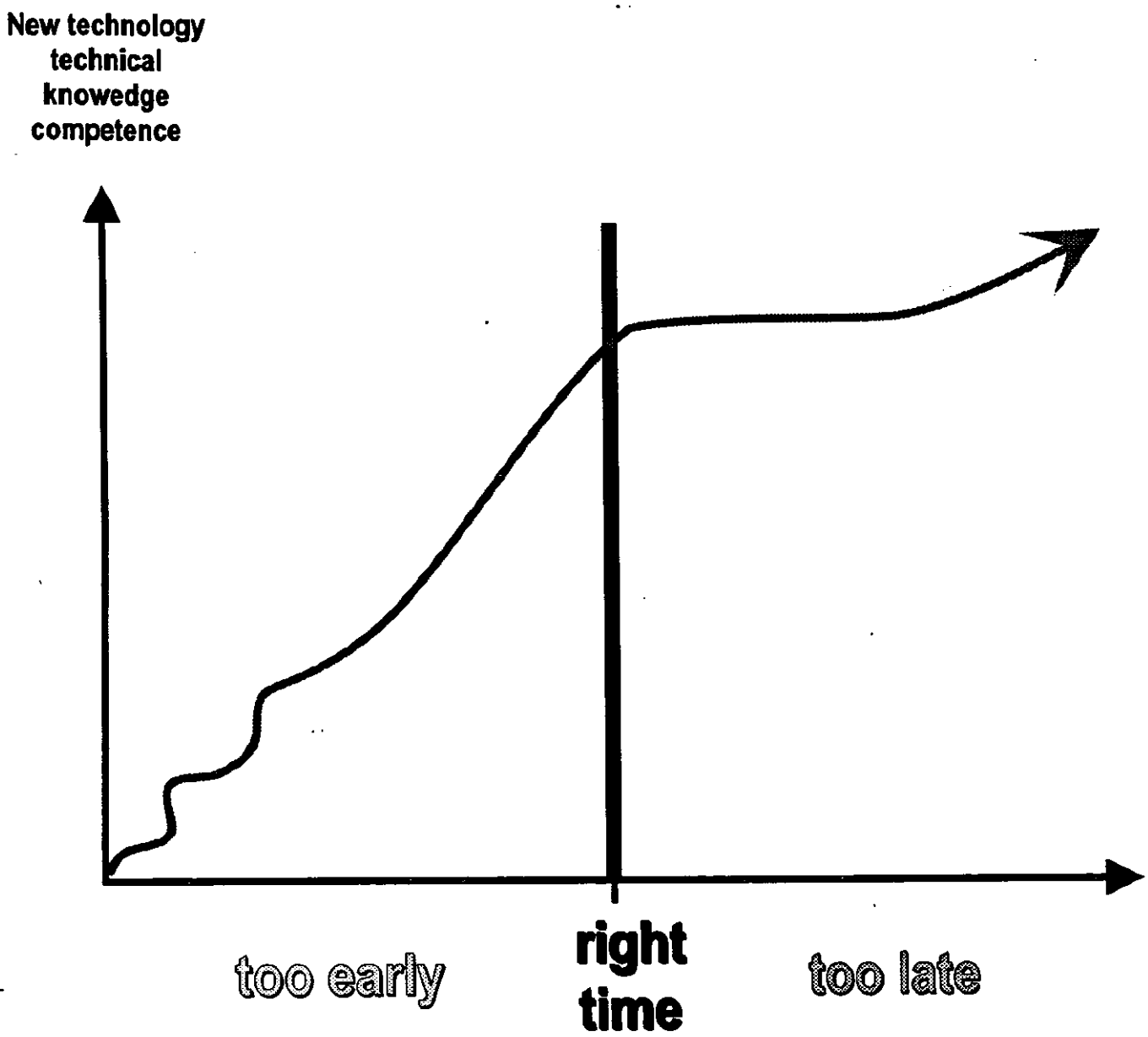
1. NPD TREAT EVERY DEVELOPMENT INDIVIDUALLY BASED ON CRITICALITY.
   INFLUENCIAL PARAMETERS ARE:
   - OWNER STRUCTURE IN LICENCES
   - SALES METERING/ALLOCATION METERING/ CRITICALITY OF ALLOCATION METERING
   - AN ECONOMIC EVALUATION SHOULD BE DEVELOPED

THE RELEVANT SECTIONS OF THE REGULATIONS ARE 9,10,13 AND 23.

2. REDUNDANT SYSTEM IS GIVING INCREASED CONFIDENCE

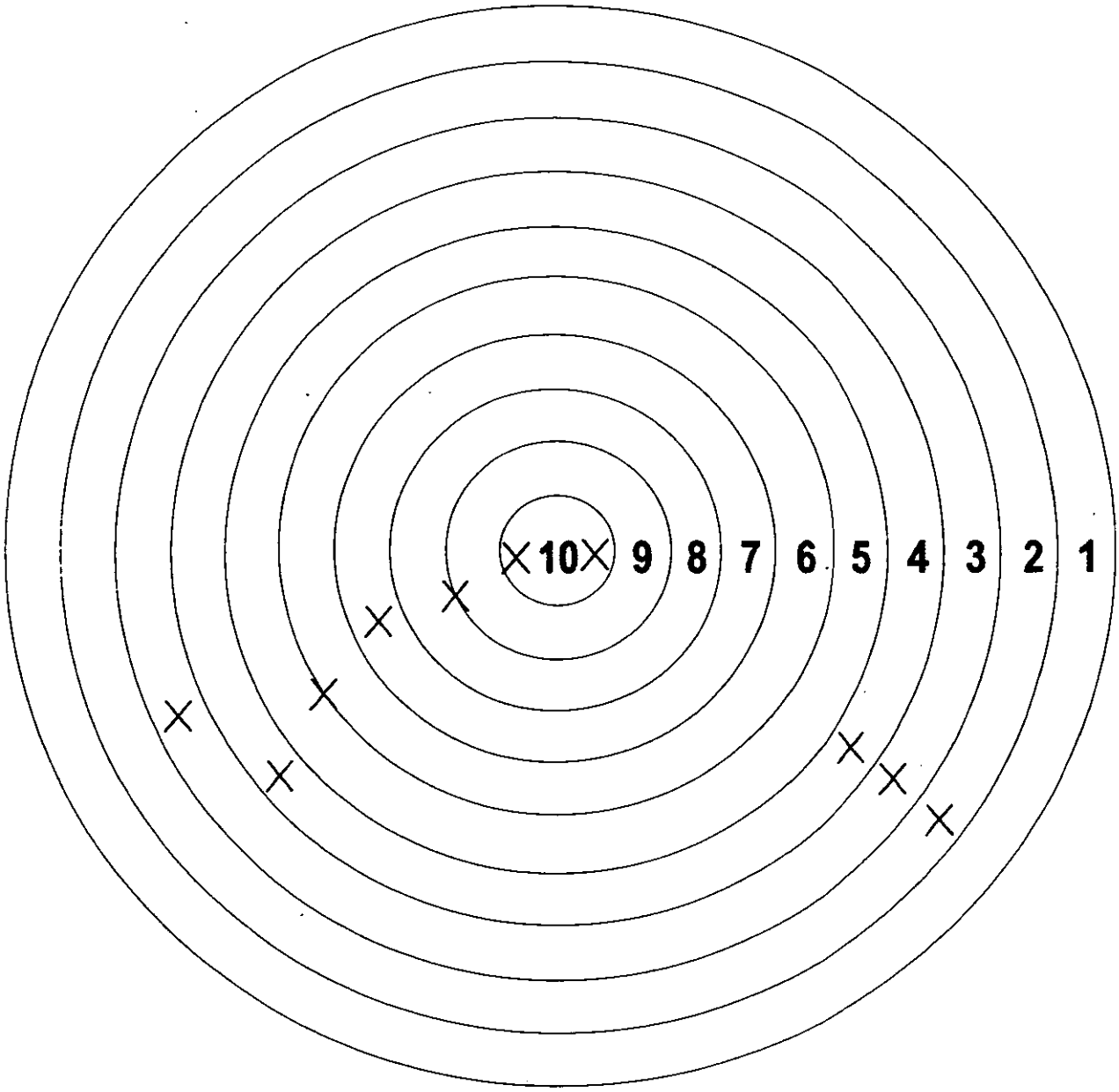
3. TEST DATA GIVES INCREASED CONFIDENCE
   - REAL TESTS

4. POSSIBILITIES FOR CALIBRATION
   - THE EQUIPMENT SHOULD BE AVAILABLE FOR CALIBRATION (MASTER METER, CALIBRATION RIG ETC.)



Whenever a decision to use new technology is taken, it is no doubt that some people will always argue that the decision was taken too late or too early

Fig



Is it possible to hit target every time?

Two professional engineers would normally have different views on where the target is on the time axis.

Fig 3

RDT 950605

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North Sea FLOW Measurement Workshop 1995

Paper 28:

POLICY CHANGES IN THE DTI'S ADMINISTRATION OF METERING REGULATIONS

6.2

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POLICY CHANGES IN DTI'S ADMINISTRATION OF METERING REGULATIONS

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DTI Oil & Gas Office,
Aberdeen

SUMMARY

The paper describes organisational changes in the Oil and Gas Division of the DTI including the setting up of a new centre for technical and administrative functions in Aberdeen. A brief review of current policy for petroleum measurement is given. This is followed by an outline of the proposed new policy to be adopted in the administration of the petroleum measurement requirements of the Regulations.

INTRODUCTION

In the last two years since we last gathered in Norway there have been a number of changes in the Oil and Gas Division of the DTI, not the least of which was the setting up of the Aberdeen Oil and Gas Office. The Division as constituted at present is shown on the first viewgraph. However Branch 6, based in Leicester now only handles work under the Gas Act which deals with downstream aspects. When the new Gas Bill is enacted Branch 6 will be moved out of DTI and into OFGAS, the Office for Gas Regulation.

The Oil and Gas Office , Aberdeen was opened in September 1993 and undertakes a wide range of duties some of which are sector oriented but many of which cover the whole UK and Continental shelf. The second viewgraph shows the structure of the Aberdeen Office, known internally as Branch 4. The technical unit comprises two sections, one dealing with subsurface aspects of fields and the other with topsides. These activities are sectoral except for the metering functions which are nation-wide in their cover.

PAST POLICY

In reviewing licensee's development proposals it has been the practice in the past to consider only the most basic elements of the measurement philosophy at the Annex B (Field Development Plan) stage and to concentrate on the detailed engineering aspects of the method of measurement at a later stage in the programme. When a licensee wished to propose a method of measurement which fell short of what was considered to be full fiscal quality metering it was necessary for the licensee to provide a fully costed justification based on both the technical and economic problems associated with the development.

The need for change

The need for change comes about as a result of changes both in the Tax and Royalty regime and in the way industry conducts its business.

More new developments are small satellites of existing fields. The scope for separate processing is severely limited. Some of the small satellites are developed using the new long reach drilling techniques, some are subsea tied back to parent platforms with long flow lines, and some through minimum facilities structures, often unmanned. Many of these new developments will have short productive lives. Fast track development programmes are becoming more common with the attendant need to define long lead time items earlier in the process. New technology is being introduced at a rate which outstrips the standards organisations to produce new standards or codes of practice.

New developments are no longer subject to PRT and Royalty but through co-processing or common transportation may impact on tax and Royalty paying fields. The Government is pursuing a deregulation policy. This does not impact directly on petroleum measurement as there are no proposals to revoke any of the clauses in the Petroleum(Production)Regulations dealing with metering. However it important that we review the way the regulations are administered in a deregulatory spirit. It is also important that we should play our part as appropriate in support of the CRINE initiative.

NEW POLICY

The new policy is not intended to be a rigid prescription for methods of measurement but rather a vehicle which will facilitate continuous consultation with bodies representative of the industry to ensure a policy which evolves with the changing circumstances in which we operate.
Greater emphasis should be placed on narrowing the options for measurement systems at the pre Annex B stage in the review process. By addressing these issues at an earlier stage than before the preferred option will be identified sooner, to the mutual benefit of all parties.

Consideration is also being given to changes in operating procedures and periodic verification requirements The review process will use a three stage procedure..

1. Identify the purpose for which measurement is required;

a) under the "measurement Model Clause" and,
b)under any other duty to measure petroleum incorporated in the Petroleum (Production) Regulations.
Amongst the most usual purposes under (a) (won and saved) are:

i) To safeguard revenues for Royalty and PRT paying fields.

ii) To allocate terminal outturns to contributing fields in shared transportation systems.

iii) To account for production of petroleum won and saved from stand alone fields not subject to Royalty or PRT.

iv) To account for petroleum in the form of crude oil, gas or lpg exported from terminals.

v) To allocate production into shared transportation systems from different fields commingled in shared process equipment.

vi) Fuel gas and utilities use.

And under (b)

i) To improve understanding of reservoir behaviour to enable effective reservoir management strategies to be implemented.

ii) To establish viability of reservoir as production prospect (EWT)

iii) Flare gas measurement

iv) To account for gas or condensate re-injected into a reservoir for pressure maintenance or conservation.

2. Categorise the class of measurement associated with each purpose.

A category of measurement may be associated with more than one purpose depending on the nature of the development Full account would be taken of the technical and economic factors associated with each development

Examples of the categories of measurement envisaged are:

i) Fiscal
ii) Allocation (continuous)

iii) Allocation (intermittent)
iv) Fuel and utilities
v) Flare
vi) Extended Well Tests
vii) Reservoir management

The list is not intended to be complete and as circumstances change new categories may be required.

3. Assign target uncertainties for each category of measurement

When agreement has been reached on the categorisation of the available methods of measurement target uncertainties would be applied to each category.

Typical uncertainties for each category are:

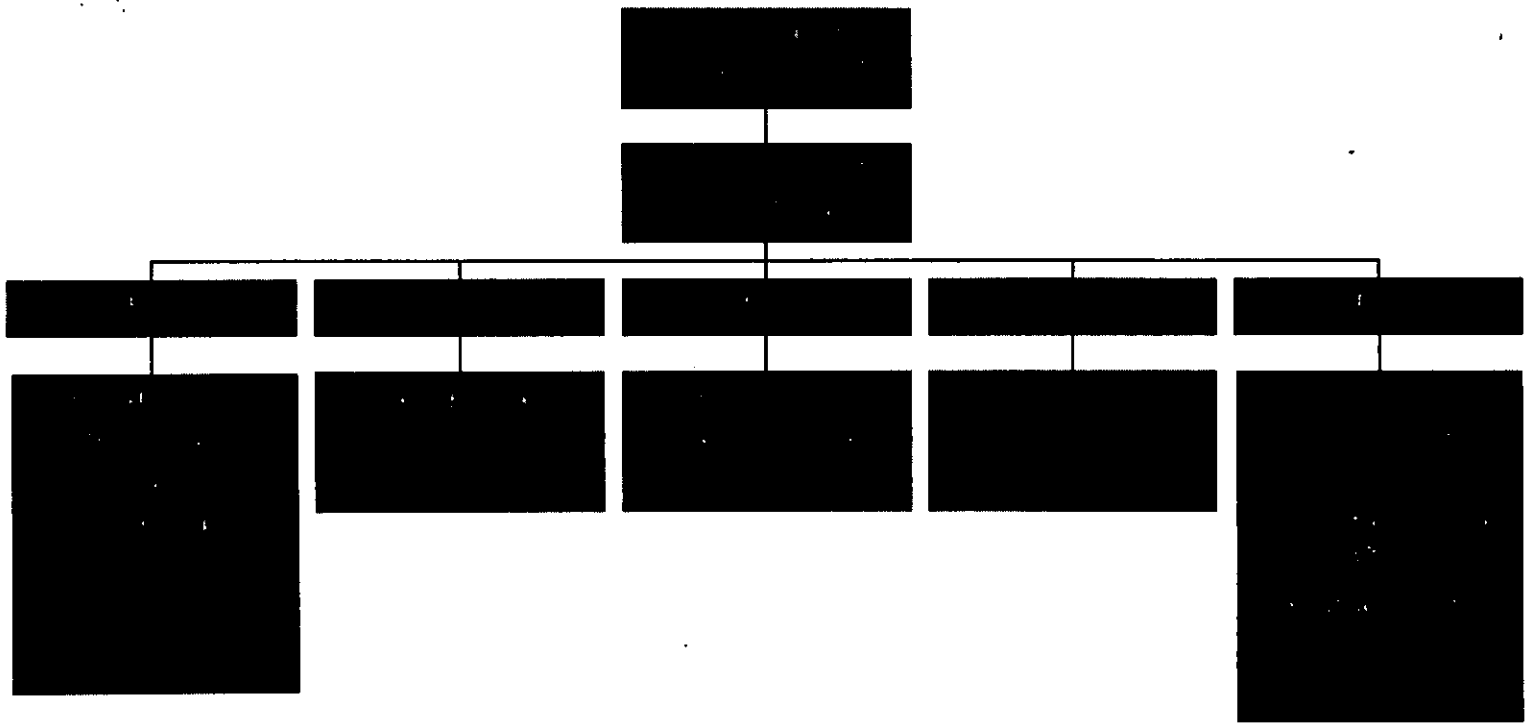
i) Fiscal:- 0.25% oil, 1.0% gas
ii) Allocation(continuous):- 0.5% to 1.0% oil, 2.0% to 3.0% gas
iii) Allocation(intermittent):- 5.0% oil and gas
iv) Fuel and Utilities:- 2.0% to 4.0% gas
v) Flare:- 10.0% to 20.0%
vi) Extended Well Tests:-_ 1.0% to 2.0% oil, 2.0% to 4.0% gas
vii) Reservoir Management:- 5.0% to 10.0%

Operating Procedures and Periodic Verification

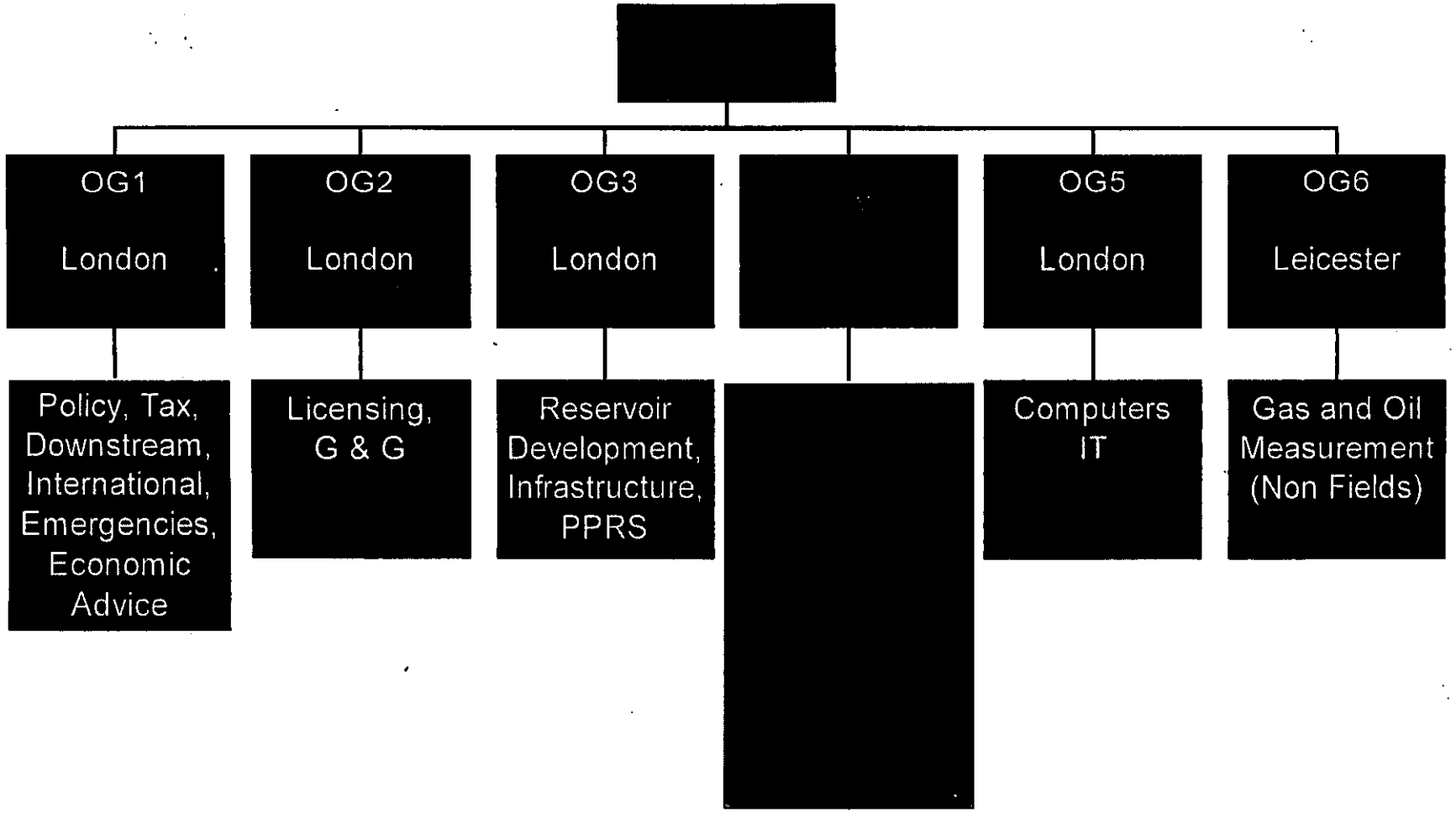
As smarter instrumentation becomes available incorporating self diagnostic capabilities and health check techniques for existing instrumentation becomes more sophisticated there may be scope to move away from verification requirements based on elapsed time and to carry out periodic verification on the basis of perceived need.

CONCLUSION

In conclusion it is hoped that the new proposals will better suit the needs of the Department and the industry for appropriate levels of measurement in the changing technical and economic environment in which we all work.



Structure of Oil and Gas (OG) Division



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North Sea FLOW Measurement Workshop 1995

Paper 29:

DYNAMIC VERIFICATION OF COMPACT (PISTON) PROVER REPEATABILITY

6·3

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DYNAMIC VERIFICATION OF COMPACT (PISTON) PROVER REPEATABILITY

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SUMMARY
The main method of establishing (piston) prover repeatability is by observing waterdraw calibration repeatability. However, being an essentially static exercise, the waterdraw procedure will not reveal any ill effects on performance introduced during normal cyclic use at realistic flow rates. Testing dynamically against devices with a better proven performance is not an option, as few, if any, exist.

To provide a better test, and thus allow higher confidence to be placed in the performance of piston provers, a test was outlined by the OIML in its doc. no. 7, employing two standard turbine meters in series with the prover being tested.

This paper explains the statistical method used and the reason it works in theory. The development of numeric acceptance criteria is described, in addition to the qualified evaluation of result chart presentations that have been used exclusively with this test method earlier. Finally, some experiences and typical results from an actual test (on a 24" Brooks Compact Prover) are presented.

+ + +

1 INTRODUCTION

The on- and offshore industrial markets have exhibited growing acceptance of compact, or piston, provers as both primary and supplementary calibration devices in fiscal metering systems. This has led to a requirement for better, but still practical methods for verification of the performance of these devices.

The testing normally used provides directly verifiable figures for up- and downstream volume repeatability, but only an indication that the dynamic performance is equally good.

Accordingly, the OIML in its doc. no. 7 has outlined a new kind of test, using statistics not only to evaluate the data, but to generate the quantity evaluated. This method allows the use of standard equipment to evaluate a device with a better repeatability.

As we shall see, the use of statistics-based testing requires that acceptance criteria not be put in absolute terms.

2 CURRENT TESTING PRACTICE

Standard testing encompasses:

- Leak check
- Waterdraw calibration
- Dynamic testing against a conventional prover

The leak check is a static exercise, performed by manually moving the piston to a designated number of positions along the (water filled) cylinder, shutting in- and outlet valves, then applying a force to the piston (the Brooks Compact Prover [BCP] uses its plenum spring pressure) while monitoring piston movement. Zero movement confirms both seal integrity and cylinder roundness.

The waterdraw calibration uses automatic start and stop circuitry to precisely transfer the downstream (and/or upstream) cylinder volume of water to a calibrated volume standard. Repeatability is determined by repeating the exercise a designated number of times.

While no proof of the claimed repeatability (0.01 %) is achieved, the final test against the conventional prover at least shows that there is no gross deviation from the performance predicted by the static tests performed. The result from this exercise is customarily expressed as a "total spread" encompassing repeatabilities from the compact prover, the transfer meter and the conventional prover. This, at best, gives a reasonable assurance that the compact prover is performing to specification.

3 OIML TEST DESCRIPTION

Two standard turbine meters with a range extending to or above the maximum for the prover on test are installed in series with the prover.

It is assumed that the two turbine meters are installed in such a way that they do not influence each other in any way; i.e. any variation in actual meter factor when running at a fixed flow rate is due to the inherent repeatability limits of that meter, and is not affected by the presence of the other meter, and vice versa. This means that deviations from the mean meter factor will vary **randomly and independently** in sign and magnitude within the meter repeatability specification.

The above assumtion means that the covariance (equation 1) of the actual meter factors will be zero when **n** (the number of observations) approaches infinity. Even with "large" but finite **n**, this may be assumed with sufficient accuracy.

Now, when the meter factors are simultaneously determined (at a certain flow rate) with the prover, the deviations from the mean meter factors will be composed of one part due to the meters' repeatabilities, and one part due to the prover repeatability, with the latter component contributing the same percentage to both deviations. Since we have just established that the meter repeatabilities will not contribute to the covariance, we may see the calculated covariance as a measure of prover performance.

When selecting turbine meters for this duty, standard specification repeatability criteria must be met. Too large turbine meter repeatability figures are unacceptable

$$cov(k_1, k_2) = \frac{1}{n-1} \sum_{1}^{n} (k_{1i} - \overline{k_1})\ (k_{2i} - \overline{k_2})$$

k_1 : k-factor meter #1
k_2 : k-factor meter #2
n : number of tests

Equation 1

because they tend to "mask" the effect of the prover, both in chart observation and calculation based evaluation (see below).

4 RESULT EVALUATION

4.1 XY CHART OBSERVATION

This method does not really require that any statistical methods be applied to the data. When the meter factor deviations for meters #1 (X) and #2 (Y) are plotted in an XY diagram, a pattern appears that can be used for evaluation of the prover performance as follows:

Little or no contribution from prover	-	Majority of points evenly distributed within rectangle defined by the two turbine meter repeatabilities.
Prover contributes	-	Points stretch out along the line defined by X=Y, moving beyond the rectangle defined above.
Difference between meter repeatabilities is large	-	Points stretch out along the X or Y axis.

If turbine meter repeatabilities are more or less the same, the emerging pattern will be reasonably regular, and the listed changes due to prover effects will be easily visible. As discussed above, "bad" turbine meters will tend to obscure the pattern, but this is easily detectable from the individual meter factor results and thus avoidable.

4.2 COVARIANCE CRITERION

As discussed, the covariance between meter factors can be seen as a measure of prover performance. In order to calculate a covariance limit and determine other criteria to apply to the value calculated, and also to determine other test parameters, some simulation is required. During preparations for the testing mentioned in **6.** below, such simulation was carried out as follows:

- The number of tests (single-pass runs) required to achieve a result sufficiently n -> ∞ was initially determined simply as the maximum number of runs per test that could be tolerated, given a reasonable time frame to complete the tests. Testing was considered necessary at 1/1, 2/3 and 1/3 of

the maximum prover flow rate, and the desired number of tests at each flow rate was approximately 6. The number of passes arrived at from these requirements was 40, and this was used in all subsequent work.

- A test simulation (a spreadsheet) was developed with the following key assumptions:

  - the turbine meter factor deviations are random numbers, with a uniform probability distribution over the range of the quoted meter specification (typical repeatability +/- 0,02 %)
  - the prover contribution to meter factor deviation is a random number, applied equally to both k-factors, with a uniform probability distribution over the range of the quoted prover specification (typical repeatability +/- 0,01 %)

- Thereafter, approximately 1,000 complete tests were simulated, and the results were used to create a probability distribution profile for the covariance.

5 ACCEPTANCE CRITERIA

The covariance distribution found above was inspected, and a limit value that would statistically allow 2/3 of tests to pass was selected. It was felt that this would discriminate better than using a maximum value with a 100% pass requirement.

Comparison of the actual calculated covariance with the above limit yields a PASS/FAIL result for each 40-run test. In order for the complete test suite to be considered PASSED, at least 2/3 of tests at each flow rate must PASS.

However, being based on an averaging calculation, this criterion does not guarantee that <u>every</u> value is within the specified limit, and does not catch situations where an initially "perfect" prover deteriorates towards the end of a test, but not enough to bring the average out of bounds. Individual turbine meter deterioration should be caught by the prover, but to further safeguard against these possible problems, an additional criterion was introduced, using the XY diagram: a predominant number of the plotted points for any 40-run test, shall be located within a square described by:

$$|x| < a$$
$$|y| < a$$

where **a** is the straight sum of maximum deviations [%] for meter and prover.

6 EXPERIENCES AND PRACTICAL CONSIDERATIONS

Our immediate interest in the method and its use was prompted by a delivery of a 24" BCP to a Norwegian onshore site. The Norwegian Weights & Measures Directorate (Direktoratet for Måleteknikk, *DFM*) wanted an OIML test to be performed during the FAT.

Earlier implementations of the OIML test had been based primarily on evaluation by observation of the XY-charts as described above. On this occasion, the DFM felt (and the

manufacturer concurred) that as far as possible, objective criteria should be used. This would allow a more uniform approach to evaluation in the future, would be more in line with tradition, and would finally be more acceptable to those writing contracts including such testing. Hence the calculation and simulation exercises described above.

During testing, the following points were noted and should be observed:

- The proviso that the turbine meter factors are independent is *not* to be taken lightly. Care should be taken when installing the temporary meter runs. Any flexible or corrugated tubing should be smooth inside; noticeable meter repeatability effects were seen with a corrugated tubing section upstream of turbine meter #1.
- Because of the fairly large amounts of data that need to be handled (possibly manually, depending on the prover electronics used), it is useful to have a spreadsheet or other system ready for immediate evaluation during testing.

7 SAMPLE RESULTS

For the particular installation mentioned above, the following data applies:

Prover (BCP) repeatability:	+/-0.01 %
Meter (Brooks) repeatability:	+/-0.02 %
Prover capacity:	1,589 m^3/h

Acceptance criterion from simulation:

- For each flow rate, approx. **2/3** of the performed tests shall result in a calculated covariance less than **4.3E-09**.

Acceptance criterion from chart inspection:

- For each test, a predominant number of the plotted points shall be located within the square described by:

$$|x| < 3.0E\text{-}04$$
$$|y| < 3.0E\text{-}04$$

Results:

LOW FLOW

Number of tests	:	6
Number passed	:	4
XY diagram check	:	Accepted
Test suite result	:	**PASSED**

MEDIUM FLOW

Number of tests	:	6
Number passed	:	5
XY diagram check	:	Accepted
Test suite result	:	**PASSED**

HIGH FLOW

Number of tests	:	7
Number passed	:	5
XY diagram check	:	Accepted
Test suite result	:	**PASSED**

OIML TEST RESULT: PASSED

After the test series had been completed, time was left to allow some further experiments. We therefore ran two test series where a variable error was introduced by generating a variable leak through a vent valve at the BCP. The main object of this was to make sure that the test method would actually catch the errors it should reveal according to theory.

The charts generated did indeed show the characteristic stretch along the X=Y line, and the covariances calculated exceeded the limit set.

ACKNOWLEDGEMENT
All work related to testing and development of acceptance criteria has been carried out in direct cooperation with or under the supervision of mr. Kristen Hellerud, DFM, Norway.

16.10.95

Main Index

North Sea FLOW Measurement Workshop 1995

Paper 30:

MULTIPHASE FLOWMETER PERFORMANCES UNDER SIMULATED CONDITIONS

6·4

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CHARACTERISATION OF THE PERFORMANCE OF MULTIPHASE FLOWMETERS: THE MULTIFLOW JIP

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SUMMARY

Multiphase flowmeters have been the subject of several individual laboratory and field trials, generally conducted to suit the requirements of a single organisation. Under the Multiflow JIP at NEL several commercially available multiphase flowmeters have been tested under a common test matrix designed to reflect the actual needs of oil companies. The test matrix was designed by NEL after consultation with the project sponsors and reflects the bias of fields to high GLR. Where appropriate to the meter technology the test matrix included the full range of water contents anticipated in the field.

The evaluations of the test meters were carried out on the NEL multiphase calibration facility using stabilised Forties blend crude and simulated produced water at two different salt concentrations. The performance of the meters under evaluation is described in terms of the percentage error relative to the reference phase flow rates, and the capability of the meters to meet the manufacturers specification.

1 INTRODUCTION

The objectives of the Multiflow project were to define a common evaluation envelope and to evaluate four multiphase flowmeters at these conditions. The evaluation matrix was designed to satisfy the needs of each of the sponsoring companies both in terms of determining the performance of the selected multiphase flowmeters at conditions near to those anticipated in the field and to assess the repeatability of each flowmeter by measuring the performance of the meters at the same conditions a number of times during the evaluation. The test matrix was designed by NEL after consultation with the project sponsors and reflects the bias of fields to high GLR. Where appropriate to the meter technology the test matrix included the full range of water contents anticipated in the field.

To simulate the type of installation expected in the field the vendor companies were invited to set-up their instruments in the NEL facility, but once the process was completed and the flowmeter was handed over no further alterations to the meter set-up were permitted unless a fault or breakdown occurred.

A significant aspect of the project was the request of the sponsors for NEL to monitor and report on the performance of the multiphase flowmeter vendors in terms of

product support and response to problems encountered during the evaluation. Comments were also sought by the sponsors on the applicability of the various technologies to field and subsea environments.

Fluids as close as possible to field conditions were used during the evaluation, a mixture of topped Forties crude and kerosene, and simulated brine formed the liquid phase, nitrogen was used to simulate the gas phase for safety reasons. The effect of changes in density and salinity of the brine was also examined by repeating part of the matrix using a water solution of higher salt concentration.

2 FACILITIES

The multiphase flow loop at NEL was used to carry out all the evaluations. The Multiphase National Standard Facility at NEL is based around a three-phase separator. This vessel contains the working inventory of oil and water in separate compartments. Each liquid phase is drawn from its separator compartment by a variable speed pump and passed, via the primary reference flowmeter skids, to the mixing section. The gas phase is passed from the supply to the mixing section via a reference meter skid. At the mixing section the water and oil are commingled and the gas phase is injected a short distance downstream. The multiphase mixture then enters the test section, which can be up to 60 m in horizontal length or 10 m in vertical height. A schematic of the facility is shown in Figure 1. For these evaluations the multiphase flowmeters were connected into the facility test section approximately 50 m downstream of the mixing section. After the test section the mixture returns to the separator, where the gas phase is exhausted to atmosphere and the water and oil are separated by gravity.

Some carry-over from the separator is inevitable and both the oil and water feeds from the separator are fast-loop sampled to measure the composition of each process stream. Conditioning circuits allow operation of the facility at a temperature between 10°C and 50°C, to within 1°C and the operating pressure may be up to 10 bar gauge. Temperature and pressure are also measured at several points in the test section, at the oil/water monitors and at the reference meters and mixing sections.

A programmable logic controller (PLC) controlled the facility operation and data acquisition from all the field instruments. The outputs from the multiphase meter under test were also connected into the PLC and logged simultaneously with the facility field instrumentation. All measurements were automatically corrected for temperature and pressure, the reference liquid flow rates were also corrected for the carry-over in the process streams. All the instruments were regularly calibrated to local secondary standards, and density curves for the liquid phases were measured before each evaluation commenced.

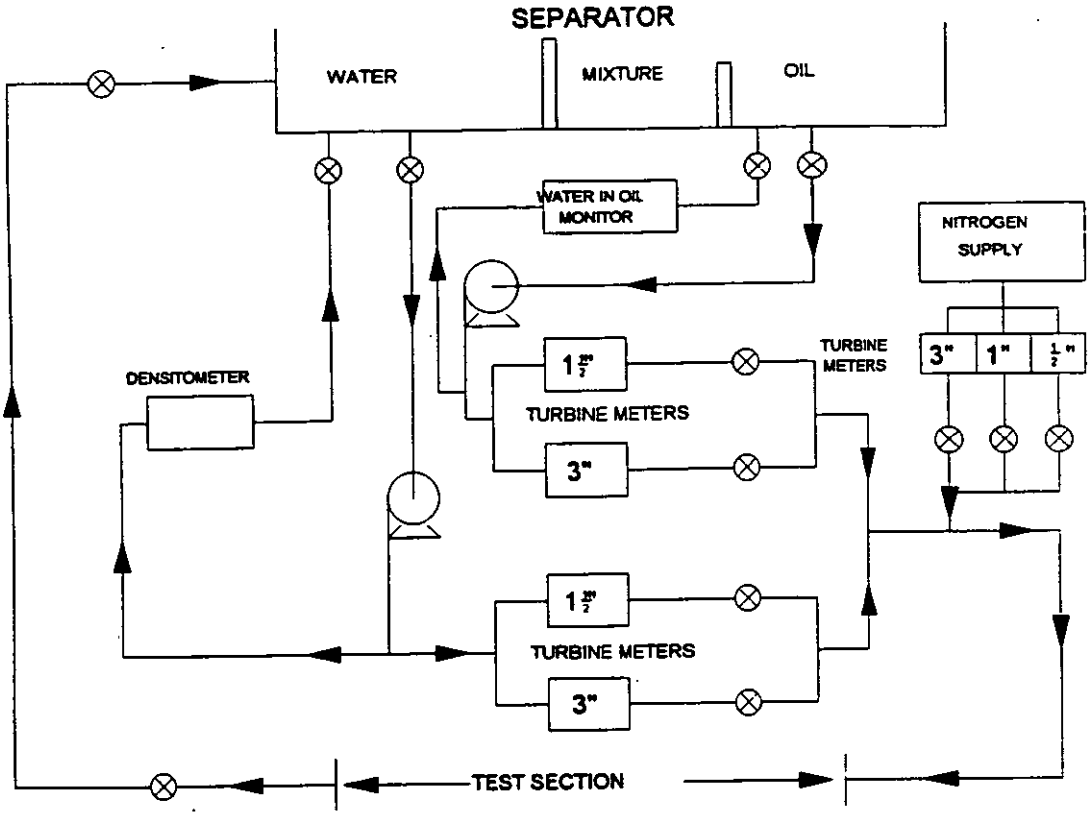

Figure 1: Schematic of NEL Multiphase National Standard Facility

The oil used during this evaluation was a mixture of stabilised Forties crude (flashpoint 60°C) and Exxsol D80 in a 70/30 ratio. The oil viscosity was 12.6 cSt at 18°C, density was 860.7 kg/m^3 at 20°C. Brine was simulated by the additional of Magnesium Sulphate ($MgSO_4$) salt to de-ionised water in two concentrations, these were 25g/l and 50g/l. The conductivity at 25°C of these solutions were 0.64 S/m and 1.05 S/m respectively, the density at 20°C was 1010.45 and 1018.4 kg/m^3 respectively. Nitrogen was used as the gas phase throughout.

The oil and water flow rates in the facility can be varied between 0.5 and 40 l/s of each phase, the maximum nitrogen mass flow rate is 0.5 kg/s. In a 100 mm test section the above flow rates can produce mixture velocities in the range 0.5 to 25 m/s at gas volume fractions in the range 1 to 99 per cent. The test section pressure can be maintained at up to 10 bar gauge, the fluid temperature may be varied in the range 5 to 50°C provided that the oil temperature does not increase to less than 20°C below the flashpoint.

All the reference flow data and process condition data is automatically logged at pre-set intervals to a time and date-stamped file. The test meter flow outputs were linked into the facility SCADA systems and were therefore logged simultaneously. Reduction of the data and comparison of the test instrument to the reference were conducted off-line.

3 TEST METERS

Several vendors were approached for loans of multiphase flowmeters for evaluation, on the basis that in return they would receive the evaluation data. The key criteria for selection of the meters was that they be commercially available instruments. On this basis the multiphase flowmeters chosen for evaluation were the Agar MPFM-301, the CSIRO MFM, the Fluenta MPFM 1900VI, the Framo MFM, the ISA ScrollFlo and the MFI LP meter. Four of these meters will be evaluated under the current phase of the Multiflow project, and the remainder will be included under the second phase (Multiflow 2). It is anticipated that as current developments become more mature they will also fulfil the requirements of the project, and will be included in the evaluations of Multiflow 2. Organisations which have already expressed interest in evaluation under the Multiflow 2 project include Mixmeter, Kongsberg and Jordan-Kent.

3.1 Agar MPFM-301

The flowmeter contains a rotary positive displacement flowmeter, modified for multiphase use, and two venturis in series in a vertically upward flow. An algorithm in the control computer derives the total, gas and liquid volume flow rates from these outputs. The water content of the flow is derived from the power absorbed by the process fluid from an in-line microwave monitor. The continuous liquid phase is detected by the phase shift between the transmitter and two differentially spaced aerials. The measurement of the liquid phase water cut can then be derived from the gas fraction and the microwave monitor output, individual oil, water and gas flow rates are then computed from these variables.

3.2 CSIRO MFM

This flowmeter uses the attenuation of gamma rays at two different energies to derive the oil, water and gas phase fractions. The mass absorption coefficients of oil and water vary as a function of gamma photon energy and the difference between the coefficients for oil and water is also a function of the photon energy. These differences can be utilised to measure the phase fractions. To maximise the transmission of the lower energy gamma rays the sources and detectors are arranged around a GRP pipe section. Velocity measurement is by cross-correlation of multiphase flow features, slugs and bubbles for example. Velocity and phase fractions are combined to give oil, water and gas flow rates.

3.3 Fluenta MPFM 1900VI

This meter uses several different sensors in combination. Capacitance and inductance sensors are used to measure bulk electrical properties of the flowing mixture in oil and water continuous flows respectively, and derive water cut from these measurements. A single energy gamma densitometer measures the average bulk density by attenuation of gamma photons. The phase fractions can then be extracted from this information. Velocity measurement is by a combination of cross-correlation of capacitance signals and venturi differential pressure in oil continuous flow and from the venturi differential pressure in water continuous flow. Velocity and phase fraction measurements are then combined to give phase flow rate information.

3.4 Framo MFM

A mixer is utilised to pre-condition the flow entering a venturimeter. The mixer consists of a large plenum chamber and piccolo tube. The piccolo tube penetrates the base of the plenum chamber and conducts the flow to the venturimeter, the aim being to draw the gas and liquid into the venturi at equal velocity. The differential pressure across the venturimeter is proportional to the total volume flow rate. A dual-energy gamma densitometer is mounted at the throat of the venturi and is used to derive phase fractions. The phase flow rates are then calculated from these and from the total flow rate.

3.5 ISA Multiphase Flowmeter

Essentially a positive displacement flowmeter this instrument contains two counter-rotating shafts. The shafts are machined to form a continuous constant volume cavity and the rotation imparted to the shafts by the fluid passing through the meter is proportional to the total volume flow rate. At the centre of the meter a single-energy gamma densitometer is mounted to measure the overall mixture density. If the water cut of the liquid phase is known then the phase flow rates can be determined from these measurements.

3.6 MFI LP Meter

Several elements are combined to measure the phase flow rates in oil continuous flow. The fraction sensor and venturimeter are mounted vertically above a static mixer. The fraction sensor contains a resonant cavity between two sets of microwave reflectors. Measurements of the RF frequency in the cavity are proportional to the water cut in the liquid phase. A single-energy gamma densitometer is used to measure the total mixture density and the gas fraction is derived from this measurement and the water cut. The total volume flow rate is gained from the differential pressure across the venturimeter, and the oil, water and gas flow rates are calculated from this and from the phase fractions.

4 RESULTS

The Multiflow project has been conducted on behalf of commercial sponsors. These sponsors do not wish to identify the evaluation results with particular instruments and so, for the purpose of discussion, the multiphase flowmeters have been identified by randomly selected letters. Manufacturers accuracy limits have also been removed to prevent identification.

4.1 Analysis

All the results were analysed by a common process, although different vendors have chosen to express the maximum errors from the flowmeters in different ways, as a percentage error of the oil, water or gas phase flow rate. The results were compared with the reference measurements from the NEL facility, which are traceable to the UK National Standards for flow measurement and are calibrated at regular intervals. The uncertainty for the reference flow measurements are ±0.5% of reading for oil and water flow rate, and ± 1 to 1.5% of reading for gas flow rate. The errors from the reference phase flow rates were expressed as percentage error of phase flow rate:

$$\%Error = \frac{Q_{TEST} - Q_{NEL}}{Q_{NEL}} \times 100$$

The results, in terms of percentage error of reference phase flow rate were plotted against the gas and liquid superficial velocities (V_s) for each of the test meters. The superficial gas and liquid velocities are defined as the mean fluid velocity were the phase alone flowing in the test section.

$$V_s\_liquid = \frac{Q_{oil} + Q_{water}}{Area} \quad : \quad V_s\_gas = \frac{Q_{gas}}{Area}$$

Lines of constant gas volume fraction (GVF) are also shown on these graphs to assist in identifying regions of low and high GVF. Regions of low total flow rate correspond to low gas and liquid superficial velocities, similarly high flow rates correspond to high superficial velocities. The magnitude of the error from the reference has been illustrated at each evaluation point within a band of uncertainty i.e. between -10 and + 10 per cent.

4.2 Meter C

The results from the meter C test using brine solution 2 are shown in Figures C1, C2 and C3 for 10 per cent water cut

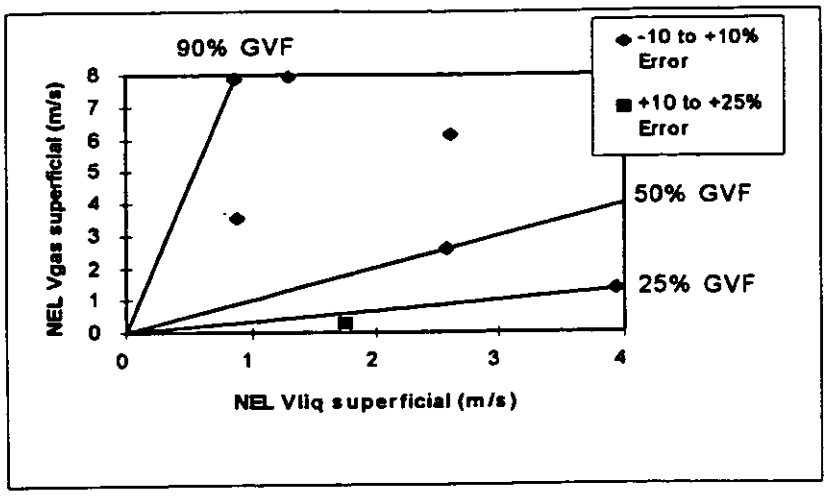

Figure C1: Oil phase flow rate errors at 10% water cut

The oil and gas phase flow rates were generally well predicted to within ±10 per cent of the reference phase flow rate at this condition, prediction of the water flow rate was less good with all the errors greater than ±10 per cent. There was some evidence of under-estimation of the gas phase flow rate at high GVF (see Fig. C3)

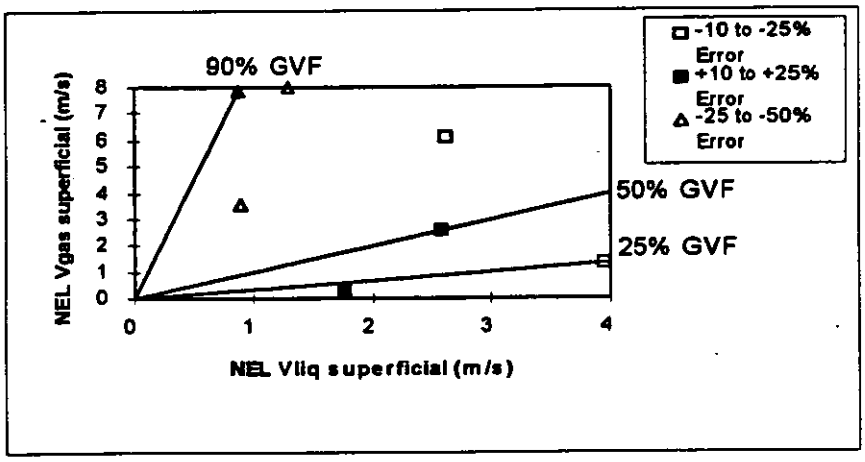

Figure C2: Water phase flow rate errors at 10% water cut

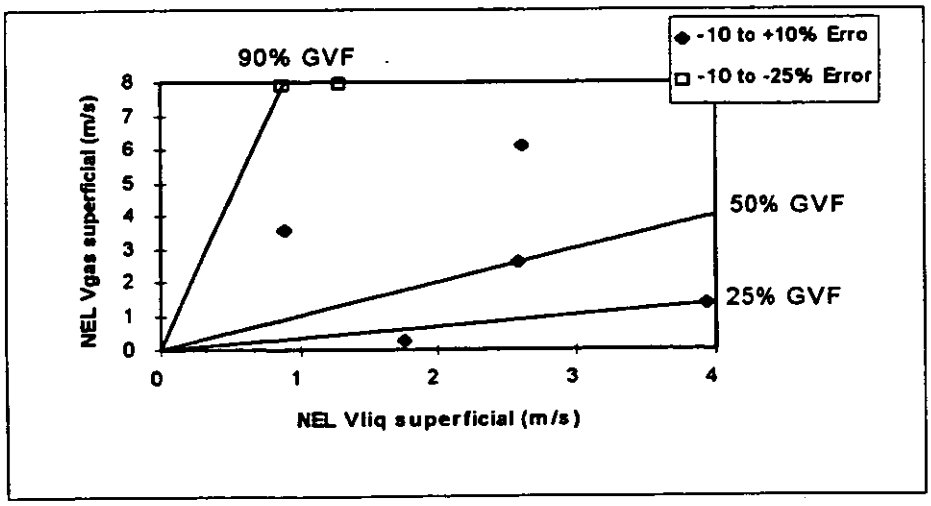

Figure C3: Gas phase flow rate errors at 10% water cut

Figures C4, C5 and C6 illustrate the results at brine solution 2 with 35 per cent water content.

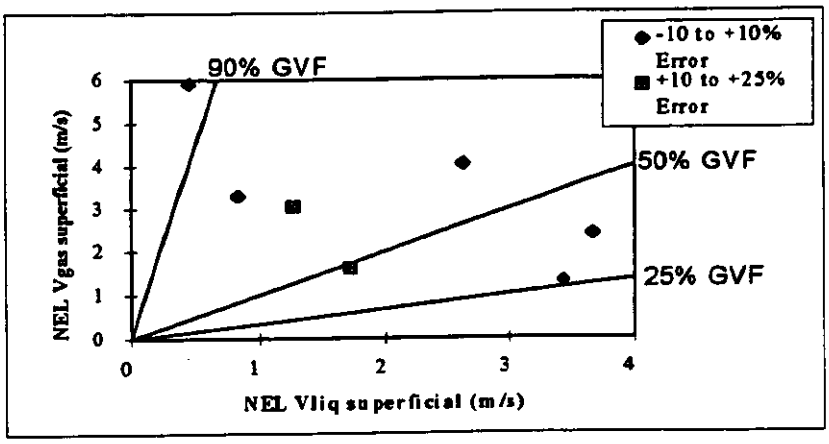

Figure C4: Oil phase flow rate errors at 35% water cut

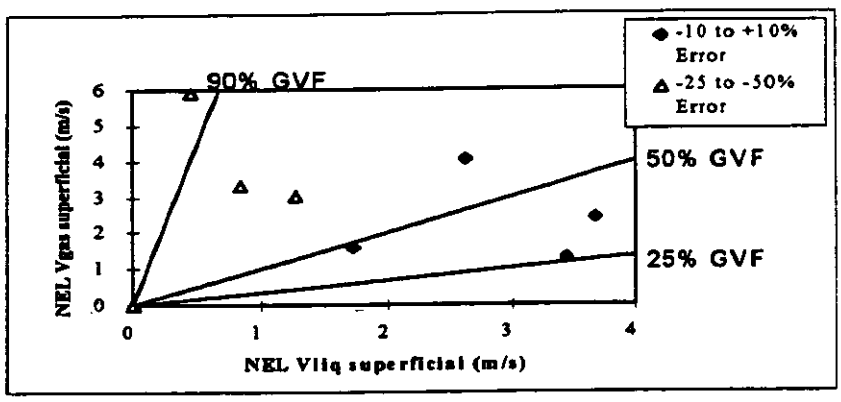

Figure C5: Water phase flow rate errors at 35% water cut

The majority of the oil and gas phase flow rates were well predicted to within ± 10 per cent of the reference condition. At the higher water cut the meter predictions were more accurate than at the 10 per cent water cut.

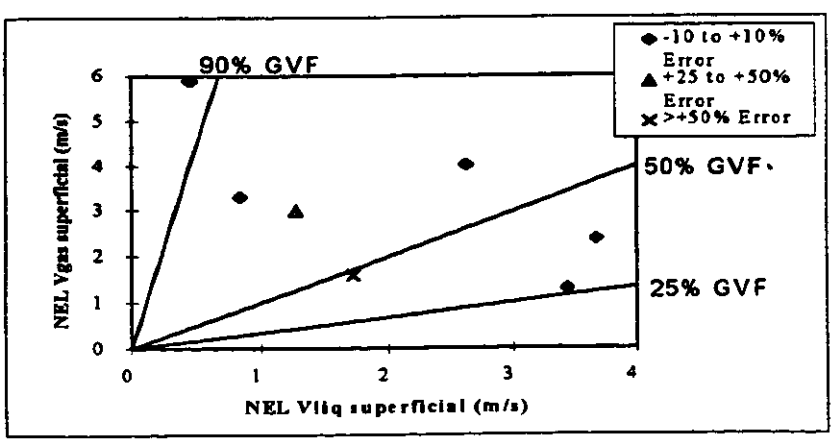

Figure C6: Gas phase flow rate errors at 35% water cut

For both water cut conditions the water flow rate was increasingly under-estimated as GVF increased, an indication that the accuracy of the water cut measurement was sensitive to GVF. The majority of the meter predictions which were within ±10 per cent of the reference were at liquid superficial velocity higher than 2 m/s. Below this level, and particularly with similarly low gas superficial velocity, greater errors were noted.

4.3 Meter Y

Data from this evaluation was unavailable at the time of writing but will be presented at the North Sea Workshop

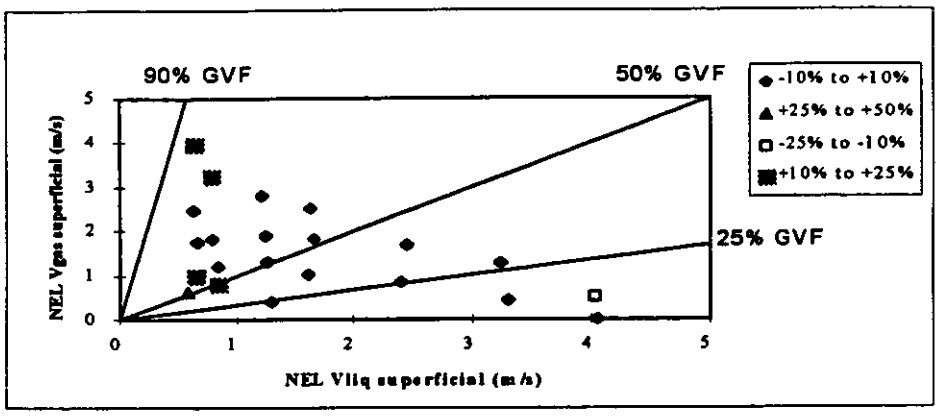

Figure N1: Oil phase flow rate errors at 40% water cut

4.4 Meter N

The results at 40% water cut for brine solution 1 are shown in Figures N1, N2 and N3.

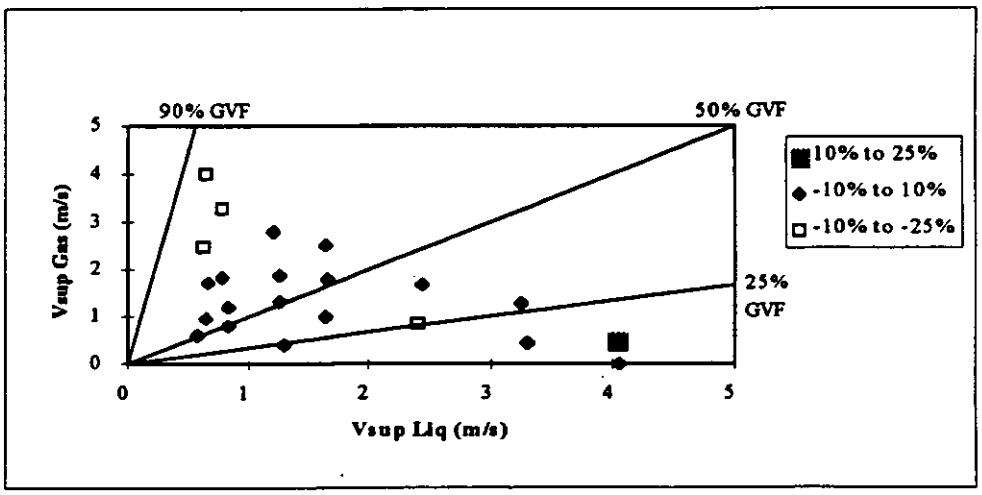

Figure N2: Water phase flow rate errors at 40% water cut

Most of the errors are within ±10 % of the reference phase flow rate. At high GVF and low liquid superficial velocity the oil flow rate was over-estimated and the water flow rate under-estimated, at these conditions an under-estimation of the water cut measurement was indicated The general trend is for water flow rate to be increasingly

under-estimated as the GVF is increased. Gas flow rate was under-estimated at low gas and liquid flow rates.

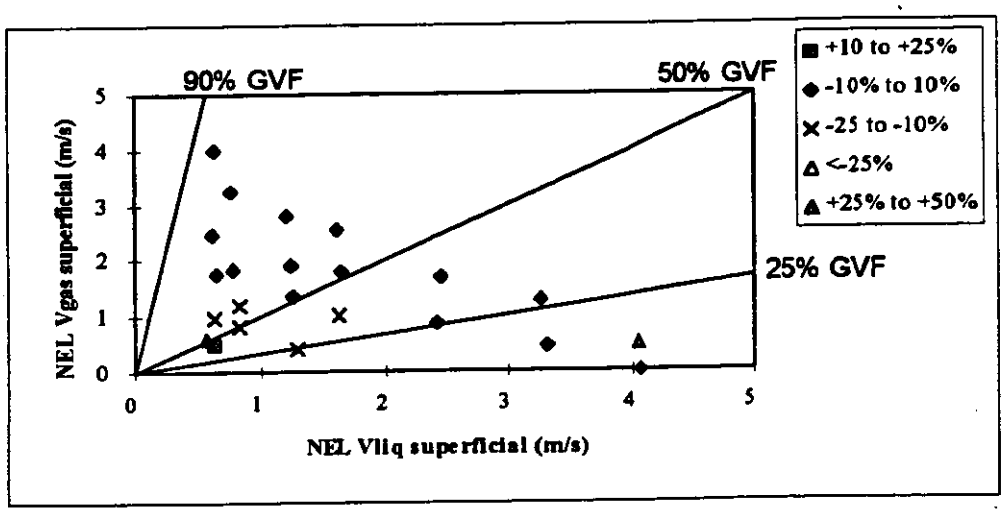

Figure N3: Gas phase flow rate errors at 40% water cut

The results at 75% water cut for brine solution 1 are shown in Figures N4, N5 and N6.

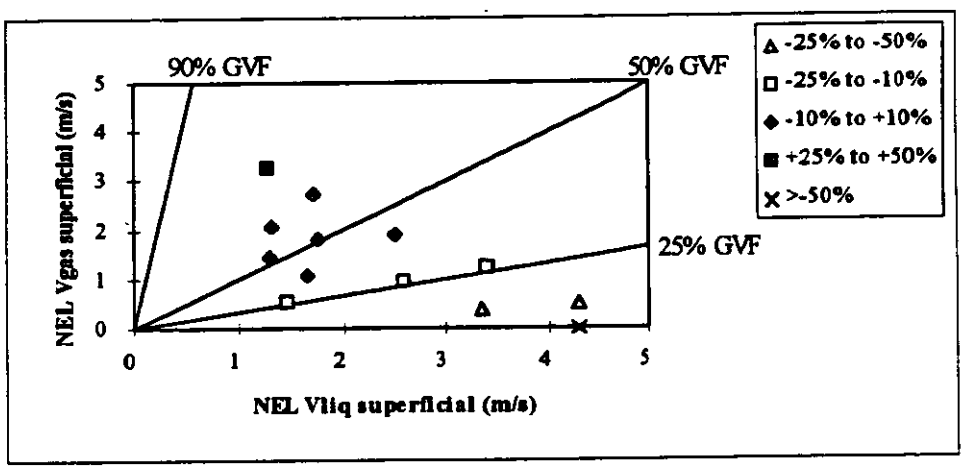

Figure N4: Oil phase flow rate errors at 75% water cut

Most of the errors are within ± 10% of the reference phase flow rate, the water flow rates were generally under-estimates within this region. The oil and gas flow rate errors were less than ±10% in the main, although the oil flow rate was under-estimated by up to 50% at low GVF for all flow rates and at low GVF the gas flow rate errors were large. The under-estimation of water content was not evident at high GVF for the 75% water cut, but the evaluation matrix did not include points above 70% GVF

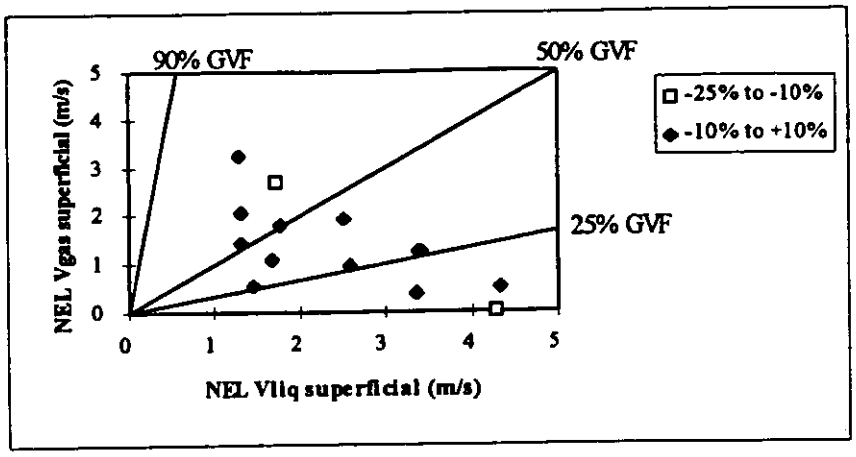

Figure N5: Water phase flow rate at 75% water cut

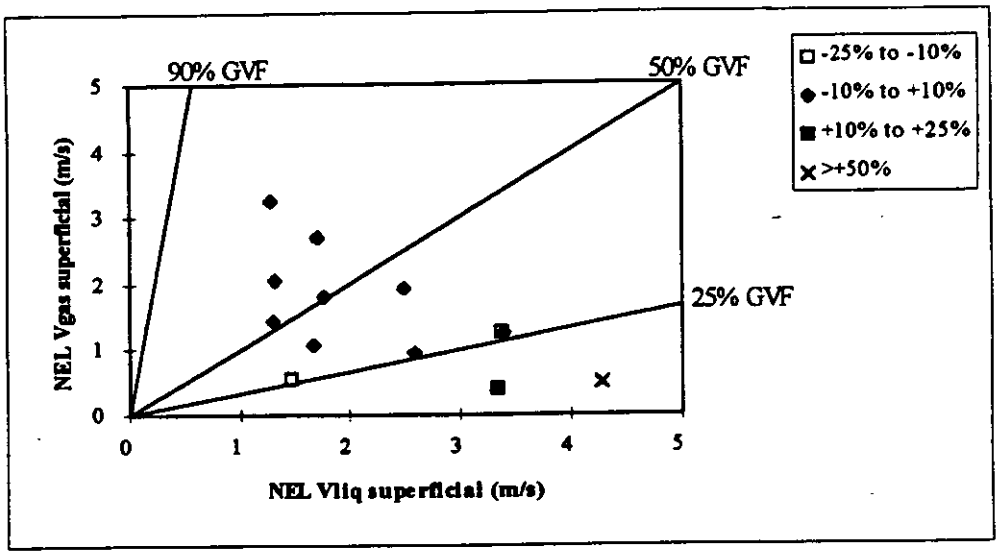

Figure N6: Gas phase flow rate errors at 75% water cut

5 CONCLUSIONS

The multiphase flowmeters evaluated to date have made use of a variety of different measurement techniques and have demonstrated that different approaches to the same fundamental problem can be equally effective.

Evaluation of the results from the meter tests has enabled the identification of regions of good and poor performance for each of the multiphase flowmeters and will help operators to select the appropriate technologies to meet the need of each field application

ACKNOWLEDGEMENTS

The author would like to thank the participants in the Multiflow JIP for their kind permission to use data gathered during this project. The participants are Amerada Hess, BP International, Brasoil UK, Exxon Production, Mobil North Sea, Schlumberger and Shell Expro UK.

Thanks also to all the manufacturers who have supported the JIP project by loan of equipment and support staff.

Main Index

North Sea FLOW Measurement Workshop 1995

Paper 31:

STANDARDIZATION WITHIN MULTIPHASE METERING

6.5

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STANDARDIZATION WITHIN MULTIPHASE METERING

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SUMMARY

On an inititive from the Norwegian Society for Oil and Gas Measurement (NFOGM) a 'Handbook of Multiphase Metering' has been developed. The handbook is intended to serve as a guide for both users and manufacturers of multiphase meters, and provide the industry with a common basis for terminology, specifications etc. in the field of in-line multiphase measurement systems. The handbook should not be regarded as a final document. Rather, it is hoped that it will initiate more international work in which the issues and topics raised here can be further developed. This paper contains extracts from the 'Handbook of Multiphase Metering'. The intention of this is to provide the reader with a picture of the scope and objective of the handbook, and further to introduce some of the more important recommendations of the handbook with respect to e.g. performance specifications, testing and qualification of multiphase meters.

BACKGROUND

The idea of developing a Handbook of Multiphase Metering was first presented at NFOGM's first annual meeting in april 1993. The idea received a very positive responce, and as a consequence the NFOGM board took the initiative to form a working group consisting of members from oil companies, manufacturers and r&d.

The committee was formed as a Norwegian working group. This was not to exclude others, but because it was felt that it was immature to start work on an international level. For this reason also the mandate for the group was restricted to drafting of a handbook for the industry, rather than drafting of an international standard.

The initiative to draft a Handbook of Multiphase Metering was presented as introduction to discussion group at the North Sea Flow Measurement Workshop in 1993. These discussion groups supported the need for a handbook, and agreed that drafting of an international standard was immature.

The NFOGM working group completed a draft version of the handbook early 1995. This draft version was presented at the NFOGM annual meeting in April, and a one month deadline for comments was given. Comment have been treated by the working group and a final document was prepared. The Handbook of Multiphase Metering is now available from the NFOGM secretariate.

This paper contains extracts from the 'Handbook of Multiphase Metering'. The intention of this is to provide the reader with a picture of the scope and objective of the

handbook, and further to introduce some of the more important recommendations of the handbook with respect to e.g. performance specifications, testing and qualification of multiphase meters.

The members of the NFOGM working group has been:

Eivind Dykesteen	Fluenta
Bernt Helge Torkildsen	Framo Engineering
Hans Olav Hide	MultiFluid International
Jens Grendstad	Kongsberg Offshore
Dag Fløio	Sandsli Drift
Harald Danielsen	Statoil
Håkon Moestue	Norsk Hydro
John Amdal	Saga Petroleum

THE OBJECTIVE OF THE HANDBOOK

The need for multiphase flow measurement in the oil and gas production industry has been evident for many years. A number of meters for measurement in multiphase flow have been developed during the last few years by research organisations, meter manufacturers, oil & gas production companies and others.

These developments employ different technologies, and the prototypes have been quite dissimilar in design and function. Some lines of development have been abandoned.

Only during the past year or two have meters been developed and tested to the stage at which multiphase flow measurement is a realistic option in an industrial environment. The number of uses and users is now expected to increase.

Multiphase flow measurement has yet to be established as a separate discipline. Meters from different manufacturers will always differ in their design, function and capabilities. In order to promote mutual understanding of multiphase flow meters and their use among users, manufacturers and others, some form of guidelines or user manual would seem appropriate. The 'Handbook of Multiphase Metering' has been written to serve that purpose and to help provide a common basis for the field of in-line multiphase measurement systems.

It is not the intention that the document should be regarded as a final document. Rather, it is hoped that it will initiate more international work in which the issues and topics raised here can be further developed.

THE SCOPE OF THE HANDBOOK

The 'Handbook of Multiphase Metering' is intended to serve as a guide for users and manufacturers of multiphase flow meters. Its purpose is to provide a common basis for, and assistance in, the classification of applications and meters, as well as guidance and recommendations for the use of such meters.

The document may also serve as an introduction to newcomers in the field of multiphase flow measurement, with definition of terms and description of multiphase flow in closed conduits being included.

The primary focus is on in-line meters for direct measurement of true multiphase flow of oil, gas and water. Even if the individual flow rates of each constituent are of primary interest, fractions of oil, gas and water are sometimes useful as operational parameters.

Other meters, e.g. separation meters and model/calculation type "meters", do not fall within the scope of this document, and are only briefly discussed. Other constituents than oil, gas and water are not dealt with.

The performance of a multiphase meter in terms of accuracy, repeatability, range, etc. is of great importance, as is the user's ability to compare different meters in these respects. One section covers this issue, and proposes standard ways of how performance can be described.

Related to performance are the testing and qualification of the meters, which are also covered. Guidance is provided to help optimise the outcome of such activities.

Since meters are in-line, flow rates are measured at process operating conditions. Conversion of flow rates to standard conditions, which involves multiphase sampling, knowledge of composition and mass transfer between phases at fluctuating pressures and temperatures, is only briefly dealt with here.

EXTRACTS FROM THE HANDBOOK

Terminology and definitions

Much of the terminology used to characterise multiphase flow and multiphase flow measurement have so far not been clearly defined. Consequently, commonly used terms are in many cases not used correctly, or may have different meanings in different contexts. The 'Handbook of Multiphase Metering' has made an attempt to put definitions to the most commonly used terminology within this dicipline. A list of the most important terms that have been defined is given below;

Flow regime
Gas-liquid-ratio (GLR)
Gas-oil-ratio (GOR)
Gas volume fraction (GVF)
Hold-up
Homogeneous multiphase flow
Multiphase flow
Multiphase flow rate
Multiphase flow velocity
Multiphase flow rate meter
Multiphase fraction meter
Multiphase meter
Oil-continuous multiphase flow
Phase
Phase area fraction
Phase flow rate
Phase mass fraction
Phase velocity
Phase volume fraction
Slip
Slip ratio
Slip velocity
Superficial phase velocity
Velocity profile
Void fraction
Volume flow rate
Water-continuous multiphase flow
Water cut (WC)
Water-in-liquid ratio (WLR)

In addition to these definitions of terminology, the handbook also gives an introduction to multiphase flow in vertical and horisontal flowlines, and gives descriptions of the different flow regimes that may be experienced. The terminology used to describe multiphase flow regimes is presented.

A format for initial evaluation of multiphase meter implementation

Two fill-in forms suitable for an initial evaluation of installation of a multiphase meter are proposed. These fill-in forms could be used by users, or by manufacturers, to compare meter performance specifications with actual process data at an intended installation point. The forms are intended as a first evaluation only, and more comprehensive investigations will have to follow before any certain decitions of suitability can be made. When using the fill-in forms, the following should be included:

- A sketch showing imortant details of the installation point:
  - upstream / downstream piping and process equipment
  - available space
  - other relevant information
- Process conditions:
  - the list in the form is not exhaustive, and other process parameters may be required
  - an attempt should be made to identify which flow regimes that are to be expected at the actual installation
- Expected multiphase production profile:
  - data to enter the graph must be given at process condition
  - superficial velocity axes should be linear, from zero to any required upper velocity range

  - secondary flowrate axes should be filled in according to the actual line size, or used to select a more suitable metering line size
  - the production profile, or multi-well production rates, should be marked on the graph, using WLR and year / well no. as legend
- Multiphase uncertainty calculations:
  - data to enter the table must be given at process condition
  - a representative number of expected production points should be filled in
  - average multiphase velocitiy, WLR and GVF may easily be calculated for each of the selected production points
  - absolute and relative deviations in measured phase flow rates may be calculated for each of the selected production points, using manufacturers performance specification

Multiphase meter implementation evaluation

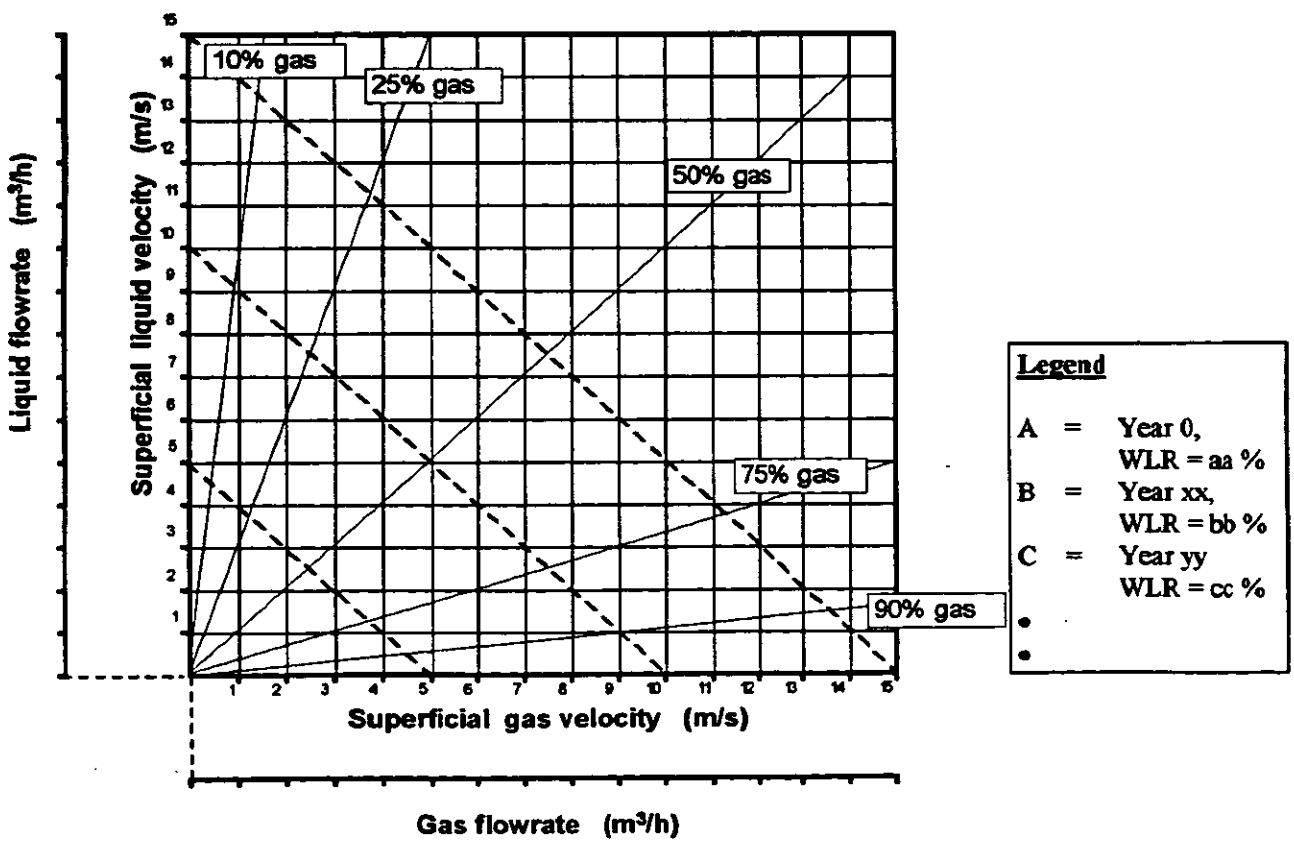
Application: _____
Installation location: _____
Date: _____
Reference: _____

Installation point piping configuration:

Process conditions:

Pressure:		**Temperature:**	
Oil density:		**Oil viscosity:**	
Gas density:		**Gas viscosity:**	
Water density:		**Water salinity:**	
Expected flow regimes:			

Expected multiphase production profile (at process conditions):



MULTIPHASE METER - UNCERTAINTY CALCULATIONS

APPLICATION:
Field:
Platform:
Installation:
Case:

PROCESS CONDITIONS:
Pressure:
Temperature:

METER DATA:
Meter type:
Model:
No of Meters:
Meter Size:
Inner Diam:

FLOW RATES - At Process Conditions

YEAR	WATER FLOW m3/h	GAS FLOW m3/h	OIL FLOW m3/h

FLOW CHARACTERIZATION

MULTIPHASE FLOW VEL m/s	WLR %	GVF %

ESTIMATED UNCERTAINTY IN EACH PHASE (1)

WATER		GAS		OIL	
relative %	absolute m3/h	relative %	absolute m3/hr	relative %	absolute m3/hr

Note: (1) Assuming calibration parameters given within uncertainty limits specified by supplier, e.g.;
- Oil density
- Gas density
- Water density
- Water conductivity

Performance specification

The preferred performance specification of a multiphase flow rate meter is given in terms of the percentage uncertainty of actual oil, gas and water volume flow rates. However, in many cases this specification will be impractical, and not suited for a best possible description of the actual meter's performance. Other frequently used specifications are therefore,

- as a percentage of the actual total multiphase flow rate, or
- as uncertainties in actual liquid and gas flow rates, and with an absolute uncertainty specification of water-in-liquid ratio.

Tables 1 to 3 provides an overview of these three different methods commonly used to describe the uncertainty of multiphase meters, applied to typical flow conditions. The resulting uncertainty numbers are presented in terms of relative (% of phase volume flow rate) and absolute (m^3/hr) uncertainty.

As is seen in these tables, even though the different uncertainty specifications at a first may look seem similar, they differ significantly.

Other methods for specifying multiphase meters exists, and the purpose of Tables 1 to 3 is to give some guidance to how different specifications can be compared, rather than providing a complete overview of the methods. Due to the significant difference in performance between these methods of expression, the manufacturer should clearly state his method of specification.

These three methods of performance specification will in the following be explained through examples:

Method 1: Uncertainties relative to actual phase flow rates.

By this method the uncertainty of the meter is described as a fixed per cent (relative) of the actual volumetric flow rate of each phase.

In the examples shown in Table 8.1, each phase volume flow rate has a $\pm$10% relative uncertainty. The resulting absolute uncertainties in terms of m^3/h are calculated as $\pm$10% of the actual phase volume flow rate.

Table 1

Specification: +/- 10 % of phase volume flow rate (WLR = 20 %)			
Fluid	**Flow rate [m³/h]**	**Uncertainty [m³/h]**	**Uncertainty [%]**
Multiphase	125	+/- 12.5	+/- 10 %
Gas	100	+/- 10.0	+/- 10 %
Oil	20	+/- 2.00	+/- 10 %
Water	5	+/- 0.50	+/- 10 %
Specification: +/- 10 % of phase volume flow rate (WLR = 4.76 %)			
Multiphase	125	+/- 12.5	+/- 10 %
Gas	20	+/- 2.0	+/- 10 %
Oil	100	+/- 10.0	+/- 10 %
Water	5	+/- 0.50	+/- 10 %

Method 2: Percentage of total multiphase flow rate.

By this method assumes the uncertainty of the multiphase meter is described as a fixed per cent of the total multiphase volume flow. The absolute uncertainty in terms of m^3/hr is thus equal for all three components for a given total flow.

In the examples of Table 2, an uncertainty level of $\pm 5\%$ is used. Of a total flow of 125 m^3/hr, this equals ± 6.3 m^3/hr, which is then the absolute uncertainty for all three phases, independent of the composition (since the total flow is the same for all four cases).

The relative uncertainty numbers can be derived simply by calculating the ratio between the absolute uncertainty and the actual flow rate for that component:

$$\delta Q_P = (Q_M * \delta X) / Q_P$$

where
- δQ_P = the relative uncertainty in phase flow rate
- δX = the specified uncertainty
- Q_M = the multiphase flow rate
- Q_P = the phase flow rate at Q_M

Table 2

Specification: +/- 5 % of total multiphase flow rate (WLR = 20 %)			
Fluid	**Flow rate [m³/h]**	**Uncertainty [m³/h]**	**Uncertainty [%]**
Multiphase	125	+/- 6.25	+/- 5.00
Gas	100	+/- 6.25	+/- 6.25
Oil	20	+/- 6.25	+/- 31.25
Water	5	+/- 6.25	+/- 125.00
Specification: +/- 5 % of total multiph. flow rate (WLR = 4.76 %)			
Total flow	125	+/- 6.25	+/- 5.00
Gas	20	+/- 6.25	+/- 31.25
Oil	100	+/- 6.25	+/- 6.25
Water	5	+/- 6.25	+/- 125.00

Method 3: Percentage of gas and liquid flow rates, combined with absolute uncertainty in WLR.

The relative uncertainty in gas flow rate is given specificly, whereas the uncertainties of oil and water rates results out of uncertainty in two levels. First, there is a relative uncertainty in the liquid flow rate, and this one must be combined with a second absolute uncertainty regarding the determination of the WLR of the fluid. It is assumed that these two uncertainties can be regarded as independant of each other.

The examples of Table 8.3 displays results for a case where the uncertainty of the gas volume flow rate is $\pm 10\%$. The liquid volume flow rate uncertainty is $\pm 10\%$, which is combined with an uncertainty of determining the WLR of ± 3 % absolute.

The absolute uncertainty in the water volume flow rate, ΔV_W, is then given by

$$\Delta V_W = \mathrm{SQRT}\ \{(\Delta WLR * V_L)^2 + (\delta V_L * V_L * WLR)^2\}$$

where
- WLR = the actual water-in-liquid ratio
- ΔWLR = the absolute uncertainty in WLR
- V_L = the actual liquid volume flowrate
- δV_L = the relative uncertainty in the liquid volume flowrate

Table 3

Specification:	+/- 10 % of gas flow rate +/- 10 % of liquid flow rate (WLR = 20 %) +/- 3 % absolute uncertainty in WLR		
Fluid	**Flow rate [m³/h]**	**Uncertainty [m³/h]**	**Uncertainty [%]**
Multiphase	125	+/- 12.5	+/- 10.0
Liquid	25	+/- 2.5	+/- 10.0
Gas	100	+/- 10	+/- 10.0
Oil	20	+/- 2.14	+/- 10.7
Water	5	+/- 0.90	+/- 18.0
Specification:	**+/- 10 % of gas flow rate +/- 10 % of liquid flow rate (WC = 4.76 %) +/- 3 % absolute uncertainty in WC**		
Multiphase	125	+/- 12.5	+/- 10
Liquid	105	+/- 10.5	+/- 10
Gas	20	+/- 2	+/- 10
Oil	100	+/- 10.5	+/- 10.5
Water	5	+/- 3.19	+/- 63.8

The relative uncertainty in water volume flow rate is then simply given by the relation between the absolute uncertainty in water volume flow rate, ΔV_W, and the actual water volume flowrate.

Accordingly, the absolute uncertainty in oil volume flow rate, ΔV_o, is given by

$$\Delta V_o = \mathrm{SQRT}\ \{(\Delta WLR * V_L)^2 + (\delta V_L * V_L * (1\text{-}WLR))^2\}$$

Establishing the reproducibility of a given meter

The reproducibility of a meter is a quantitative expression of the agreement between the results of measurements of the same value of the same quantity, where the individual measurements are made under different defined conditions.

One significant difference between multiphase meters and single-phase meters is that most of the uncertainty of a multiphase meter is caused by variations in process conditions and fluid properties, rather than the uncertainty of the primary measurement elements. Therefore, the meter's ability to reproduce its performance under different process conditions, installation set-ups and flow regimes becomes a very important parameter.

A format for the presentation of a multiphase meter performance specification

A fill-in form for summarizing the performance specification of a multiphase meter is proposed. The fill-in form could be used by users, or by manufacturers, to assemble essensial information from different manufacturers product information packages, to a common format. When using the fill-in form, the following should be included:

- A sketch showing imortant details of installation requirements:
  - horizontal / vertical upwards / vertical downwards flow
  - mixer / not mixer
  - straight upstream / downstream lengthts
- Rated conditions of use:
  - the list in the form is not exhaustive, and other parameters important for the particular meter should be included
  - flow regimes that the meter is designed to handle should be listed
  - the interval in which the influence parameters are allowed to vary, still maintaining the uncertainty specifications, should be specified
- Influence quantities:
  - the list may, or may not, include the same parameters as listed "Rated conditions of use"; all influence parameters important for the particular meter should be included
- Operating range:
  - superficial velocity axes should be linear, from zero to any required upper velocity range
  - secondary flowrate axes may be used to denote or select a suitable meter size
  - operating range should be marked on the graph, and may be divided into as many sub-areas as required
- Uncertainty specification:
  - uncertainties should be given for each sub-range of the operating range
  - uncertainties in phase flowrates should preferably be given relative to actual phase flowrates
  - absolute deviations in WLR and GVF may be given as indicated
  - the uncertaity specification may be quoted for as many WLR-ranges as required
- Additional information:
  - method of meter calibration / special calibration requirements must be identified
  - reference to more comprehensive product information should be indicated

Multiphase meter performance specification

Manufacturer: _____
Meter type: _____
Date : _____
Reference: _____

Required Installation Configuration Schematic:

Rated conditions of use:

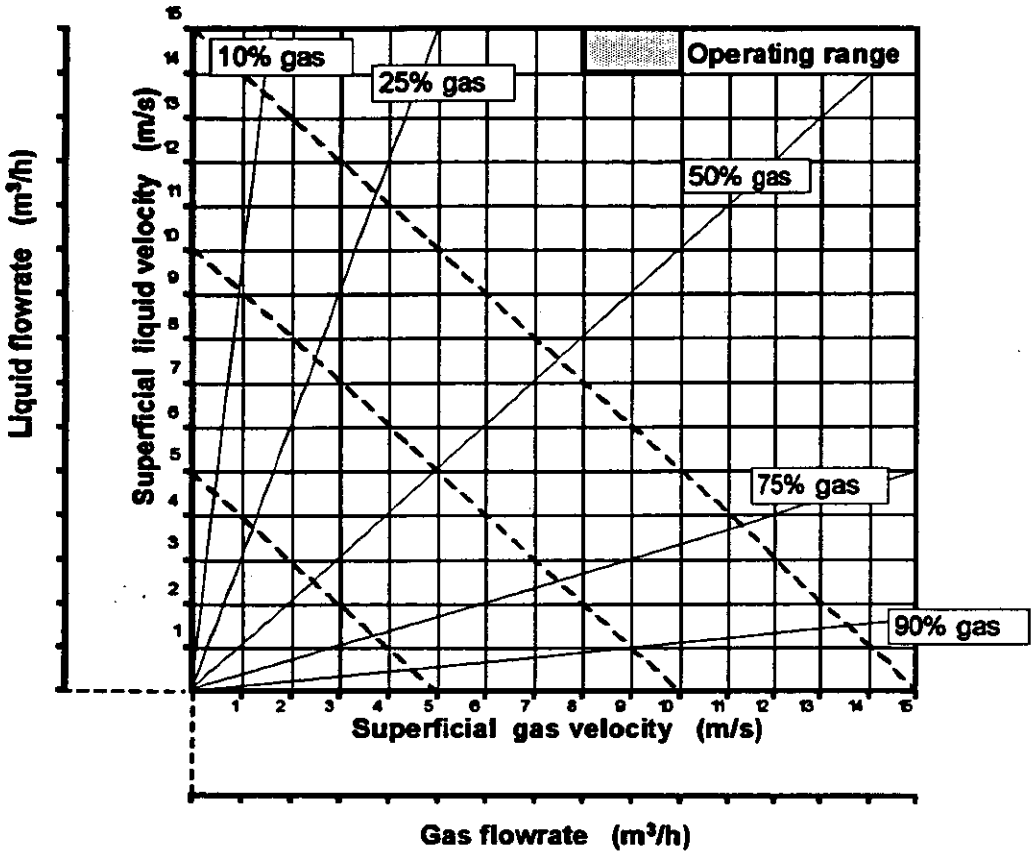
Pressure:		**Temperature:**	
Oil density:		**Oil viscosity:**	
Gas density:		**Gas viscosity:**	
Water density:		**Water salinity:**	
Flow regimes:			

Influence quantities:

Quantity	Influencing	Effect
Oil density:		
Gas density:		
Water density:		

Flow regime:		

Operating range:



Uncertainty specification:

Sub - Range	WLR Range (%)	Uncertainties; according to Method 1, 2 or 3				
		Oil	Water	Gas	Liquid	WLR
A	0 - x					
B	0 - x					
C	0 - x					
D	0 - x					
E	0 - x					
A	x-100					
B	x-100					
C	x-100					
D	x-100					
E	x-100					

Calibration requirements:

Reference:

A format for presentation of summary test results.

A fill-in form for summarizing test results of a multiphase meter is proposed. The fill-in form could be used by users, or by manufacturers, to present summaries from different tests, and of different meters, using a common format. When using the fill-in form, the following should be included:

- A sketch showing imortant details of the test installation:
  - horizontal / vertical upwards / vertical downwards flow
  - mixer / not mixer
  - straight upstream / downstream lengthts
  - phase commingling point / distance to meter under test
  - position of reference measurements
- Process conditions:
  - the list in the form is not exhaustive, and other parameters important for the particular test should be included
  - flow regimes that the meter under test has been subjected to, and how these regimes were controlled or observed
- Reference measurements:
  - type and quality of reference measurements shold be provided
  - reference to installation point on installation sketch should be given
- Multiphase meter calibration prior to test:
  - a qualitative description of the calibration performed by meter manufacturer, or by test institution, prior to the test
  - reference to a complete calibration report should be provided
- Test matrix:
  - superficial velocity axes should be linear, from zero to any required upper velocity range
  - secondary flowrate axes should be filled in according to the actual meter size
  - test-points should be marked on the graph, using WLR as legend
- Test results summary:
  - a representative number of test points should be filled in
  - deviations in phase flowrates should preferably be given relative to actual phase flowrates
  - absolute deviations in WLR and GVF may be given as indicated
  - the uncertaity specification may be quoted for as many WLR-ranges as required
  - any particular observations during test should be identified in the comments field
  - reference to a more comprehensive test report should be indicated

Multiphase meter test summary

Meter identification: _____
Test location: _____
Test period: _____
Test responsible: _____

Test Installation Configuration Schematic:

Process conditions:

Pressure:		**Temperature:**	
Oil density:		**Oil viscosity:**	
Gas density:		**Gas viscosity:**	
Water density:		**Water salinity:**	
Flow regimes (how observed):			

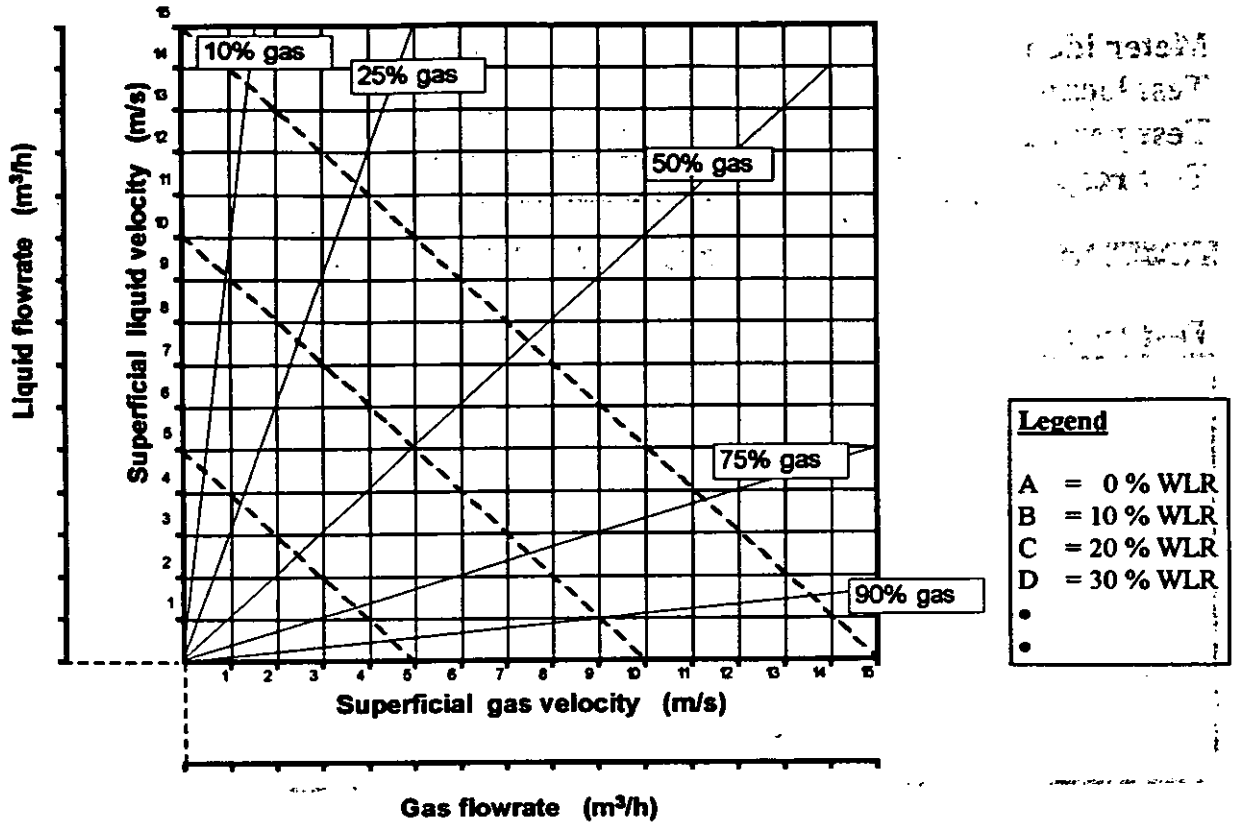
Reference measurements:

Phase	Reference meter type	Position (ref. to Piping Config. Schematic)	Uncertainty	Comments
Oil				
Water				
Gas				

Multiphase meter calibration prior to test:

Description:	
Calibrated by:	
Date of calibration:	
Reference to calibration	

Test Matrix:



Test results summary:

Reference measurements (m³/h)			Test results (m³/h)					Deviations;				
Oil	Water	Gas	Oil	Wat.	Gas	Liq.	WLR	Oil	Wat.	Gas	Liq.	WLR

Comments:

Test report reference:

Main Index

NSFMW'95

REPORT FROM

GROUP DISCUSSIONS

Lillehammer 25.10.1995

SAMPLING - SAMPLERS, ANLYSIS AND MONITORS

Chairman: Steinar Fosse

1) -It is an agreement in the group at the time now should be right for starting to us on line water oil meters. It will pay itself by saveing of labour costs.

-NEL is doing reseach work in comparing on-line water in oil meters from various vendors.

-The authorities will require comparison tests against existing sampling equipment for the first units. When confidence is established then it can be regarded as standard equipment.

2) -Sampling equipment is often wrongly designed. The equipment is often not receiving the right attention in the project phase.

-Sampling equipment is also from time to time wrongly operated. This is due to lack of proper instructions and training of the operation/maintenancee personnel.

-On-line chromatographs are normally not fiscal on the North Sea intallations.
The high uncertainty in the determination of the cost components have been regarded as and obstackle.
The aim is that new validation on projects should be launched.
The On-line gas chromatographs could then be an alternative for both colorific value (CV) and density determination.

-The authorities are waiting for a well documented application.

SELECTION OF FLOW METERING CONCEPTS I & II

Chairman: Nils Erik Hannisdal/Trond Hjorteland

-Functional specifications has to many references to international standards which lay 20-25 years behind the use of new technology.

-Projects tends to maximize on a decrease of capex and are note focusing on the opex. This focus also should be in the mind of the suppliers industry.

-New metering concept should be openly discussed with the Authority long before they become to be a realized. The Autority body, oil company and suppliers should openly discuss in an informal way as we do here on this workshop.

-The OIML - approach and the WIB organisation in the Netherlands seems to be very vital and could perhaps be a model for Norway to adopt as regards testing/qualification and verification of new technology and new concepts.

-It should be an more open communication betweeen all parties involved (oil companies, suppliers, Authorities) in custody transfer systems special, when it comes to charing test results experience.

-It should be an instrument defined to share risks/loss/profit between the oil company and the supplying industry when any project is undertaken.

-It seems to be a change in attitude as regards concervatism. North Europe is less conservative than South Europe. We are more open minded to new equipment i,e USM/U-CON etc.

ULTRASONIC GAS METERS I

Chairman: Trond Folkestad

STATUS
-Test installations / long .....tests (years)
-Lab tests
-Flare & Firegas applications
-Back-up for turbinemeters
-Allocation measurements
*Ground results from all the above activities
-PTB/NMI approval (end of year)
-Reluctancy to use the technolgy, WHY.

FUTURE APPLICATION
-Fiscal metering
-Custody transfer

USER NEEDS / TECHNOLGY "GAP"
-Noise problems from valves / regulations
    -Attepmts to use "silencers"
-Need a standard?
    -Can not wait for a standard
    -Difficult to write a commond standard.
    -Need a procedure for Authority acceptance.
-Need redundancy build into one ultrasonic meter.

ULTRASONIC GAS METERS II

Chairman: Mark Wilson

<u>Applictions</u>

Fiscal - fuel/flaregas, process flow, custody transfer including allocation

Main interest of group in gas metering. Main driving force for U/S meters still in Fiscal/Allocation. Wider rise of the technology and reporting would increase confidence and acceptance of the technology.

U/S Meters Now and the Future

Generally agreed that these are the meters of TODAY as well as of TOMORROW. The writing is on the wall for the "washer" in fiscal/allocationcustody transfer application. Accuracies getting to levels where even Turbine meters may be challenged.

Improved signal handlng etc. providing more opportunity for U/S meters with potential for Mass flow, Energy flow and with application of CFD techniques better calibration will be possible by prediction of corrections for installation effects.

VOS to look at MW, Density, Caloritic value
VOS + diagnostics - determination of liquid content in wet gas

On-going Standards Work

GRI & SWRI, ISO TC 30/WG20 - ISO Tech Report, GERG Phase 1+2, BSI standard prposals.

Percieved Major Advantages

Safety, B, Directional, Built-in Redundancy, Self Verification of status/measurement confidence.

Concerns Still Not Yet Fully Answered

No standards, noise, Installation, Proving, Lack of confidence and experience by useers/system houses/contractors - Education needed, true cost of ownership, transsducers design - effects of corrosion, liquids, blowdown, still a "blackbox"-technology, Type approval.

MULTIPHASE FLOW MEASUREMENT GROUP I

Chairman: B. Priddy

1.Operator application needs

-High GVFs/large meters worlwide
-Best accruacy (5% relative on phase) 5% or better for field allocation.
-whole life service design
-Some non-European operators learning about current capability
-Downhole measurement-future

2. Industry needs

-Agreed test/qualification methodology
-Forum activity
-Operational experience database (implies openess to share data)

3. General points

-Flexible packaging of systems to accommodate whole life service needs.

4. CALL FOR FEEDBACK

on the Norwegian Society - Handbook of Multiphase Metering from all parties world wide.

IN-SITU CALIBRATION

Chairman: Jon Eide

-Careful consideration of any timedelay in signal processing and calculations. Especially ultrasonic meters.

-Status of standarization work regarding calibration of ultrasonic meters.

-The compact prover is a accurate and reliable tool in order to carry out in-situ calibration.

-Calibration by raioactive tracers is probably a method with holds a potential in the years to come, espesially for allocation metering.

-There may be a possible demand for portable gas meter provers.

MULTIPHASE METERING II

Chairman: Chris Wolff
Attendance: 13 users, 2 consultants, 15 suppliers.

1. How to specify user requirements and meter performance.
- Before entering into the discussion reference was made to both the handbook of multiphase metering (NFOGM report nr. 1, 1995) and the paper by Slijkerman et-al. presented by Jamieson on 25.10. 95.
A clear point of contention emerged: many users can not determine whether a meter is suitable for their application from the way test results are presented usually ie.an error US oilrate or GVF or any other parameter. The multidimentional character of the performance requires that one present operation envelopes, both in the two phase map and GVF watercut map.
A minor point was whether the twophase map should be lineair (as in the handbook) or logaritmic. This was not resolved.

-Other point discussed were: the representativeness of loop tests for the real world; The need for high pressure high flow rate test loop(s).

2. The multiphase meter marked

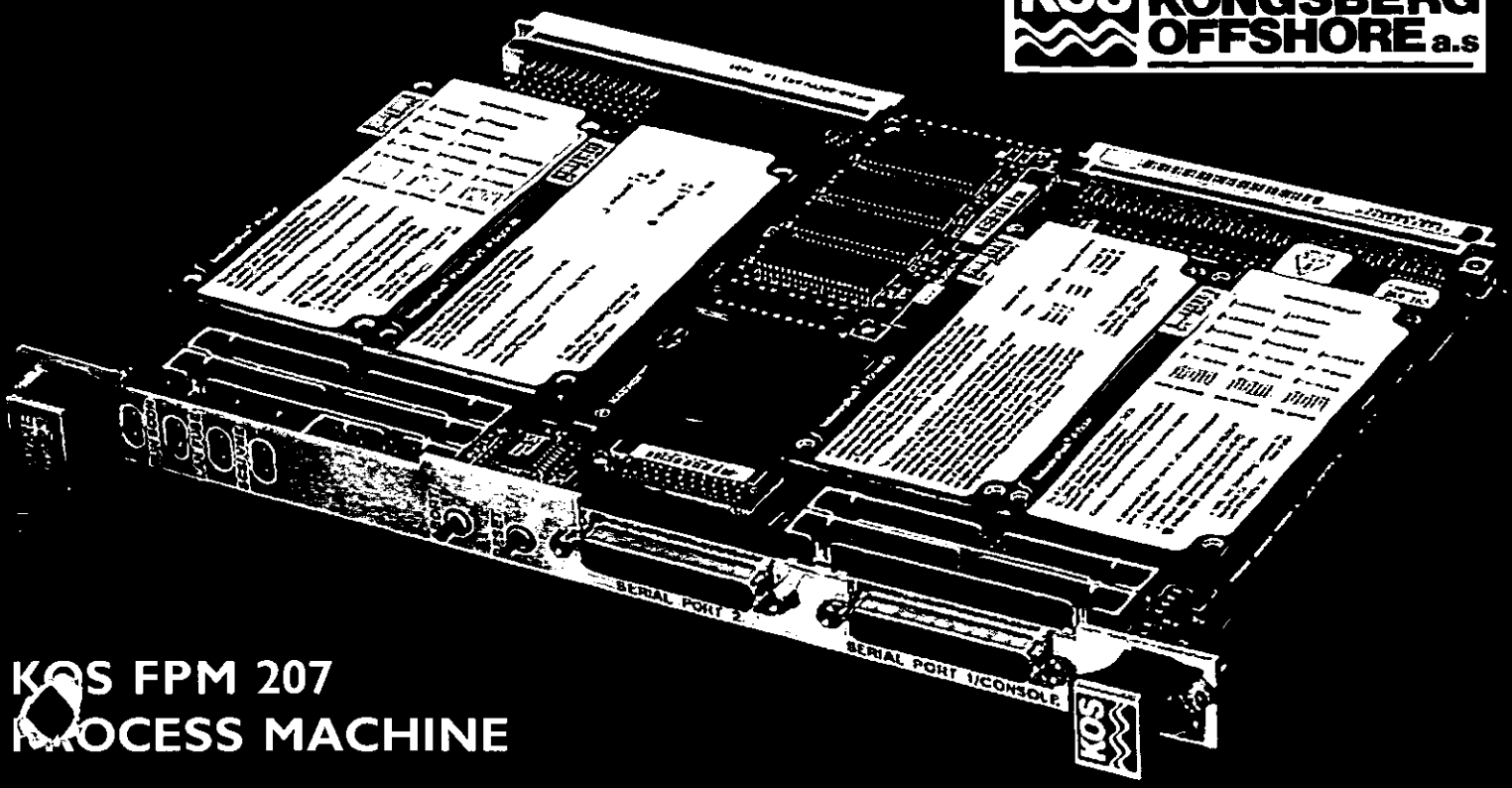
-There are 30 000 to 40 000 wells drilled each year, only 50 or 100 subsea. The first multiphase meter installations are likely to serve typically 10 wells via a test manifold. Hence the initial annual marked is never bigger than 3000 to 4000 , or 5 to 10 subsea per year.

At surface the price has to be low compared to a test separator to be attractive , ie. much smaller than 0,5 Million $. Subsea the potential savings are bigger then the meter may cost more. However when considering a multiphase meter the key question at this moment is about performance. which is often considered not adequate yet. The price issue comes only after the performance.

3. Wet cas / gas condensate measurement.

-Options considered were:
a) venturi measurement only, but with wetness correciton or
b) venturi plus gamma ray measurement. Some vendors claim that they can demonstrate good performance with option b). Not every one was convinced of that yet. This has to be followed up.

KOS KONGSBERG OFFSHORE a.s



KOS FPM 207 PROCESS MACHINE

KOS FPM 207 is a new generation process machine incorporating the functionality of a high end flow computer for both liquid and gas metering, as well as a prover controller and a programmable logic controller. Each of these functionalities have been implemented with no compromise on quality or sophistication. The choice of the latest technology industry standard hardware platform ensures a safe and reliable upgrade path and removes the risk associated with in-house development of proprietary hardware. The software implements all calculations and algorithms required to achieve maximum metering accuracy, and meets or exceeds user requirements as regards operation and maintenance. The structure of the software provides a solid, well tested foundation for implementation of user-specified functionality or future developments of metering calculations and algorithms.

SPECIFICATIONS

HARDWARE

Processor board
Motorola MVME 162 with MC68040 32bit CPU with integral Floating Point Unit. Capable of taking up to 4MB RAM, 1 MB Flash, and 512k SRAM.

I/O
IndustryPack intelligent I/O modules:
- Digital IP with 16 optocoupled inputs and 16 outputs.
- Analogue IP with 4 outputs and 8 inputs, 12 bit + sign.
- Serial IP with 8 RS232 channels, capable of smart communication by means of RS232/HART signal converters.
- Counter IP with 3 frequency inputs, 2 dual channel or 4 single channel turbine meter inputs, and 4 interrupt inputs for detector switches. Contains a high stability time base with temperature stability better than ±5ppm.

Network
IEEE 802.3 network (Ethernet) between process machines and with the supervisory system.

SOFTWARE

Operating system
Microware OS9 real-time operating system.

Programming
- ANSI C compiler is used for generating executing code.
- PC tool for user configuration of database, as option.
- IEC 1131-3 compliant PLC programming language for sequence and logic control, as option.

Database
Object based data structure held in SRAM.

Communications
- TCP/IP based communication between process machines and with the supervisory system.
- Modbus protocol for communication with external devices.
- HART protocol for communication with smart transmitters.
- RS232 / VT100 for communication with portable PC.

GENERAL DESCRIPTION

KOS FPM 207 consists of a single processor board housing the central processor unit with support circuitry, conventional memory, battery supported memory and read-only memory. The processor board can take up to 4 piggyback I/O modules which allows for almost any combination of input and output by plugging in the appropriate modules.
In a system configuration the individual process machines communicate on a network with each other and with the supervisory system. Each processor maintains an object database containing both process values, calculated results, parameters and configuration data. This data is held in SRAM and will not be lost during power failure.
Program code and metering constants are held in Flash-EPROM and cannot be altered by the user.

USER INTERFACE

In a multistream configuration the user interface will normally be provided by the supervisory system. For maintenance and local operation the process machine provides a user configurable menu-based man-machine interface running on a laptop computer or other VT100 compatible terminal. Each processor board is connected to an individual control panel. The basic configuration of the control panel includes a line maintenance key switch, a common alarm LED, and a heartbeat LED controlled by the watchdog function.
Options include counters for flow totals and pulse errors, and a display / keypad for local operation and indication.

INSTRUMENT INTERFACE

Input and output signals are handled by the I/O modules based on the IndustryPack standard, called IP modules. In the standard configuration a process machine is fitted with:

- one IP module for digital I/O,
- one for analogue I/O,
- one for serial/smart communication,
- and one for frequency measurements, pulse counting and detector switch signals.

Communication with analogue transmitters is based on the Rosemount HART protocol. To preserve full accuracy the communication is in fully digital mode. When required, the process machine may be fitted with a different I/O configuration, choosing from the wide selection of IP modules available.

GENERAL FUNCTIONALITY

KOS FPM 207 can handle up to 3 metering streams in any combination of gas and liquid streams. The configuration is controlled by the database whereas the software is unchanged. KOS FPM 207 can operate both as a Client and as a Server in a network of process machines or networked with external systems. This Open Systems design ensures good scalability and integration capabilities and provides a safe environment for implementation of application software.
The software structure is modular and operates in a multitasking environment centered around a common database. The database contains all configuration data, process data, results and parameters. I/O scanners, communication routines, man-machine interface and fiscal algorithms, all interact with the common database through a well defined Application Programming Interface.
Checksum verification of both program code and metering data is performed at regular intervals to ensure integrity of vital software and data.

LIQUID FUNCTIONALITY

KOS FPM 207 incorporates the functionality required for both a stand-alone flow computer, a prover controller and a process machine operating in a tightly integrated system network. It is equally suited for both continuos metering as well as batch metering.
The following features are included:

- Flow calculations to API, IP and ISO standards.
- Turbine meter dual pulse train handling to ISO 6551, Level A, error detection and correction.
- 4 sphere detector switches read for each proving trial with recording of accurate time and pulse count for each. Detector switch diagnostics performed.
- Pulse interpolation to ISO 7278/3, dual chronometry.
- Proving sequence control for both bi-directional, controlled launch and free launch, unidirectional, and compact provers.
- Single K-factor as standard, 10 point K-factor curve with parallel curve correction, as an option.
- Densitometer handling, common or per stream.
- Temperature measurement compensation in accordance with IEC751 equations, optionally based on calibration certificate data.

Batch metering functionality includes batch start, hold, stop, recirculation mode, non-resettable totals, retroactive meter factor. Pump control, back pressure control as well as loading arms control is optionally provided.

GAS FUNCTIONALITY

KOS FPM 207 can operate both as a stand-alone gas flow computer and in a multistream system configuration.
The following features are included:

- Flow calculations to API, ISO and AGA standards.
- Flow calculation based on differential producers is performed in accordance with ISO 5167.
- Turbine meter calculations according to AGA7, ISO/DIS 9951.
- Ultrasonic transit time meter handling.
- Densitometer handling with three Velocity of Sound correction equations.
- Density and compressibility calculations according to AGA 8, GERG88.
- Calorific value calculations in accordance with AGA5, ISO 6976.

The time base for flow totalisation is derived from a high stability oscillator. The frequency can be measured externally for verification purposes. Measured frequency can then be entered into the database and the offset will be automatically compensated for in software.

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